Cyclic Steam Stimulation Designing for Two Horizontal Wells

Mahmoud Zohair and Tagwa A. Musa
Petroleum Engineering Department, Sudan University of Science and Technology (SUST), Khartoum, Sudan
mahmoud.alkarimy@gmail.com , hushamali66@gmail.com, tagwam@gmail.com

Husham A. A. Elbaloula
Petroleum Engineering Department, Sudan University of Science and Technology (SUST), Khartoum, Sudan
Now at State University of Campinas (UNICAMP), Campinas, SP, Brazil
hushamali66@gmail.com,

Abstract:

Thermal methods are the most used EOR methods. Thermal processes can reduce viscosity of heavy oil and residual oil saturation to improve mobility and achieve an economic recovery. Cyclic Steam Stimulation (CSS) is one of the thermal methods, which has faster production, lower costs and lower pressure operations.
The main objective of this paper is to find the optimum well location and injection parameters of the CSS process of two horizontal wells in sandstone reservoirs in order to increase the sweep efficiency and improve the production from this field. The field is one of heavy oil fields with low API of 17.7 and high oil viscosity of 3800 cp at 29^{o} C.
Optimum CSS parameters and several simulation models for different development scenarios have been built using an advanced thermal EOR simulator. Many scenarios have been conducted with different parameters and conditions, and compared to study the feasibility of applying CSS in horizontal wells.
The designing model and prediction of future performance up to 2030 show that, implementation of CSS in two horizontal wells with optimum location and optimum CSS parameters can give additional 11.4 % recovery factor compared to cold 10 vertical wells. The final optimum result shows that oil recovery could be improved from 24.29 % by 10 cold vertical wells to 35.7 % by CSS in the two horizontal wells.

Keywords: Cyclic Steam Stimulation (CSS); Horizontal wells; Sandstone Reservoirs; Advanced Simulator

Introduction

EOR processes defined as “any process in which heat is introduced intentionally into a subsurface accumulation of organic compounds for the purpose of recovering fuels through well. Thermal enhanced oil recovery (TEOR) is one of the important types of EOR. CSI, CSS, also called Huff n’ Puff, is a thermal recovery method which involves periodical injection of steam with purpose of heating the reservoir near wellbore. One well is used as both injector and producer, and a cycle consisting of three stages; injection, soaking, and production. The cycle repeats to enhance the oil production rate.
When enough amount of steam has been injected; the well is shut down and the steam is left to soak for some time not more than few days. This stage is called soaking stage, where the reservoirs heated by steam, consequently oil viscosity decreases.
Since 1980, horizontal wells began capturing an ever-increasing share of hydrocarbon production. Horizontal wells offer the following advantages over those of vertical wells: 1. Large volume of the reservoir can be drained by each horizontal well, 2. Higher productions from thin pay zones, 3. Horizontal wells minimize water and gas zoning problems, 4. In high permeability reservoirs, where near-wellbore gas velocities are high in vertical wells, horizontal wells can be used to reduce near-wellbore velocities and turbulence, 5. In secondary and EOR applications, long horizontal injection wells provide higher injectivity rates, and 6. The length of the horizontal well can provide contact with multiple fractures and greatly improve productivity. (Ahmed T, 2010).
Steam simulation of horizontal wells has been tested in many fields. Mendoza et al. (1997) has initiated steam stimulation of horizontal wells using two processes: conventional Cyclic Steam Stimulation (CSS) and Single-Well Steam Circulation (SWSC). Horizontal wells typically yield higher primary recovery than vertical wells due to their larger contact area with the reservoir; with the use of steam as both heating and lifting agent, additional recovery is achieved. The well completion designs utilized conventional equipment to minimize costs and to focus efforts on the new stimulation processes with the use of standard completion. Preliminary results for SWCS in the Tia Juana field

indicate success as one well has increased its oil production rate by 200 BOPD for one year. The results for CSS in the Bachaquero Field indicate 1000 and 600 BOPD as initial productions (Mendoza et al. ,1997).
Escobar et al (2000) present and developed a new methodology for optimizing the cyclic steam injection process for vertical and horizontal wells. The procedure integrates oil production characterization using numerical simulation; the optimization algorithm was successfully validated with published results obtained from the discrete maximum principle. The methodology was then applied to determine the optimal conditions of cyclic steam injection for a horizontal well located in Bachaquero field, Venezuela (E. Escobar, et al, 2000).

Horizontal wells are becoming a very important component in the thermal recovery of heavy oil reservoirs. The success of a cyclic steam injection project depends strongly on the selection of key parameters, such as cycle length and amount of steam injected. The numerical simulation of horizontal wells, especially under non-isothermal conditions, is computationally demanding. When optimization is combined with numerical simulation, the computing time requirement may be prohibitive and it is not guaranteed that the optimal conditions will be found (James, 2013).

Elbaloula and Musa (2019) studied the implementation of cyclic steam stimulation to enhanced oil recovery for a Sudanese oil field. Their study showed that the CSS is very successful and the average oil rate is almost 1.6 times the cold production, which makes it more attractive method as development scenario for FNE oil field.
The oilfield in this study was put into development in June 2010. By May 2011; before the steam flooding study started, a total of 43 wells has been drilled, including one horizontal well. 36 wells have been put into operation, of which 23 wells are producing as cold, and 13 wells for steam stimulation. 33 wells were opened with a daily oil production of 5722bbl, a daily fluid production of 6097 bbl, a water cut of 6.1%. The total Original Oil in place (OOIP) is 298.7 MM Stock Tank Barrel (STB), and the up-to-date recovery factor of reserves is 0.75%. The average daily production for steam stimulation is 2 to 3 times of the cold wells (Elbaloula et al., 2016).
The main objective of this paper is to find the optimum well location and injection parameters of the CSS process of two horizontal wells in sandstone reservoirs in order to increase the sweep efficiency and improve the production from the field and compare the results with 10 vertical cold wells.

Material and Methods

A dynamic, model for a sandstone reservoir consists of 87291 blocks (61×53×27) has been built with no any well drilled in the model. Simulation begins from 6-5-2009 to 6-9-2030 as a prediction. The simulation model was run using a thermal simulation software for different scenarios with different length, different direction of horizontal section, and different steam parameters to make an optimization between all the scenarios. The general workflow of the study can be found in figure (1), and the process of sensitivity analysis and optimization is clear in figure (2).

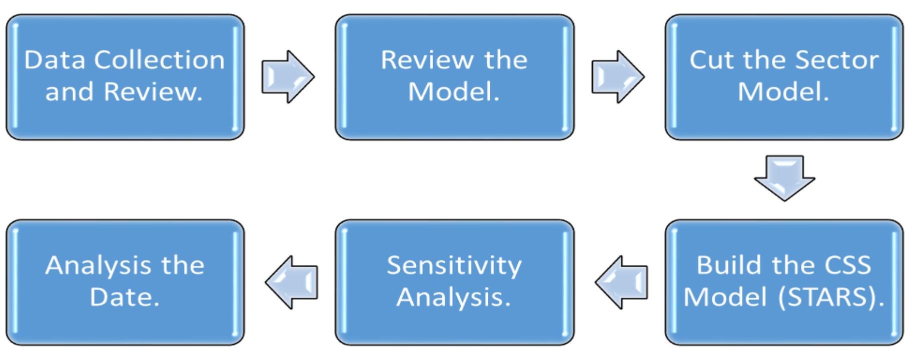

Figure. 1: General Workflow of the study

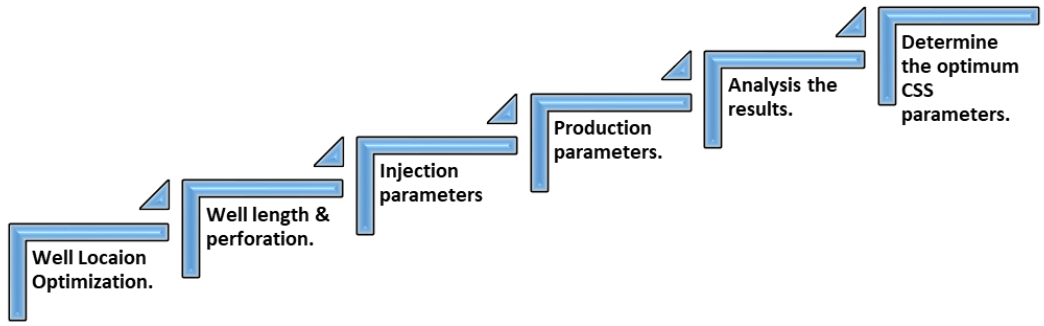

Figure. 2: Process of Sensitivity Analysis and Optimization

Results and Discussions

The case study of this paper is FNE which has a big STOOIP and low recovery factor. The field is one of the Sudan's heavy oil fields with low API of 17.7 and high oil viscosity of 3800 cp at 29^{o} C (Elbaloula, et al., 2020).

The sandstone formation divided into four layers according to the porosity and saturation (Figure 3). The main objectives are to propose the optimum design for CSS in two horizontal wells, study the ability of CSS application in these wells, and compare the results with the vertical wells case

Many models have been built and run to determine the following parameter: 1. Best location of wells (location sensitivity), 2. Best direction for horizontal section and best horizontal section length (length and direction sensitivity), 3. CSS optimization, and CSS parameter (Temperature, Quality, injection rate, injection period and soak period)

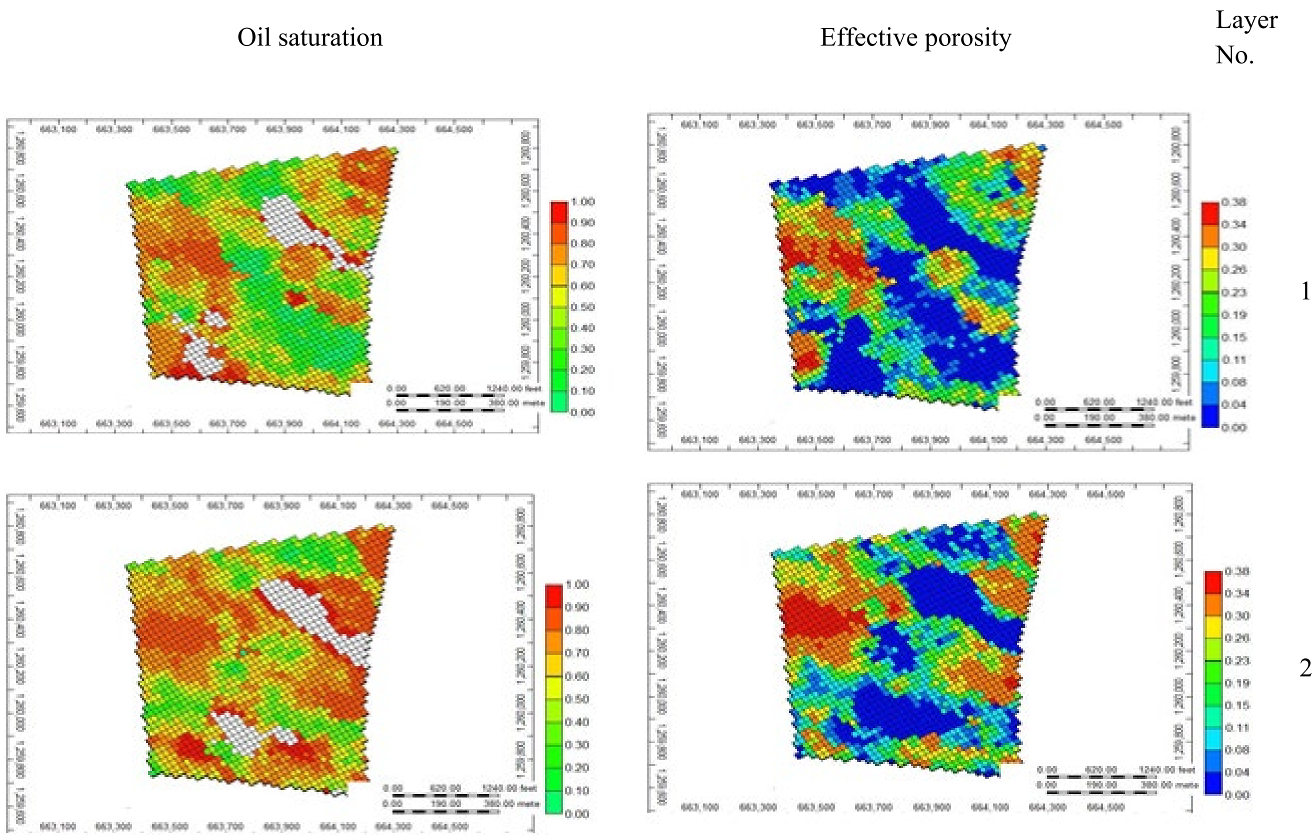

Figure. 3: Oil Saturation and Effective Porosity with Layers Number

Location Sensitivity:

10 vertical wells have been drilled in different pales depending on oil saturation and porosity distribution shows in figure 3. Figure 4 shows the locations of the wells. Production rate of 200 m^3/day and bottom flowing pressure of 200 kPa have been used for all the wells. The model was run with the ten vertical wells until 2030; and the cumulative oil production, water cut, and recovery factor has been noticed in every well and for the field. Well-1001 shows the highest cumulative oil production with 460394 bbl (table 1).
Simulation shows the cumulative oil production from the field was increased until 2018 while there is very limited oil production after this time. The total cumulative oil volume in year 2030 is 3.3 M bbl, the water cut was reached 94.9 %, and the recovery factor is about 24.3% in 2030 (figure 5)

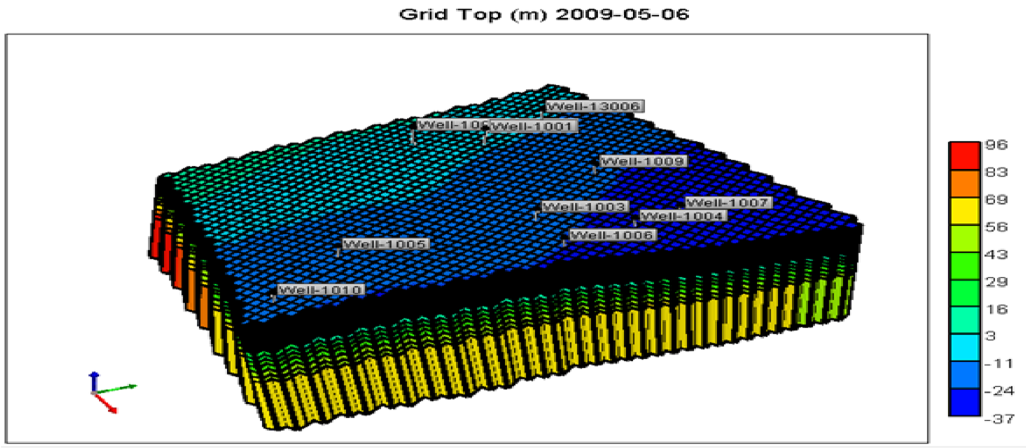

Figure. 4: Grid Top in 3D Show Location of Wells Depend on Porosity and Oil Saturation.

Table (1): Cumulative Oil production of the Ten Vertical Wells

	Well Name	Cumulative Oil (bbl)
1	1001	460394
2	1002	342095
3	1003	308736
4	1004	377411
5	1005	177601
6	1006	340507
7	1007	369144
8	13006	318778
9	1009	354319
10	1010	244273

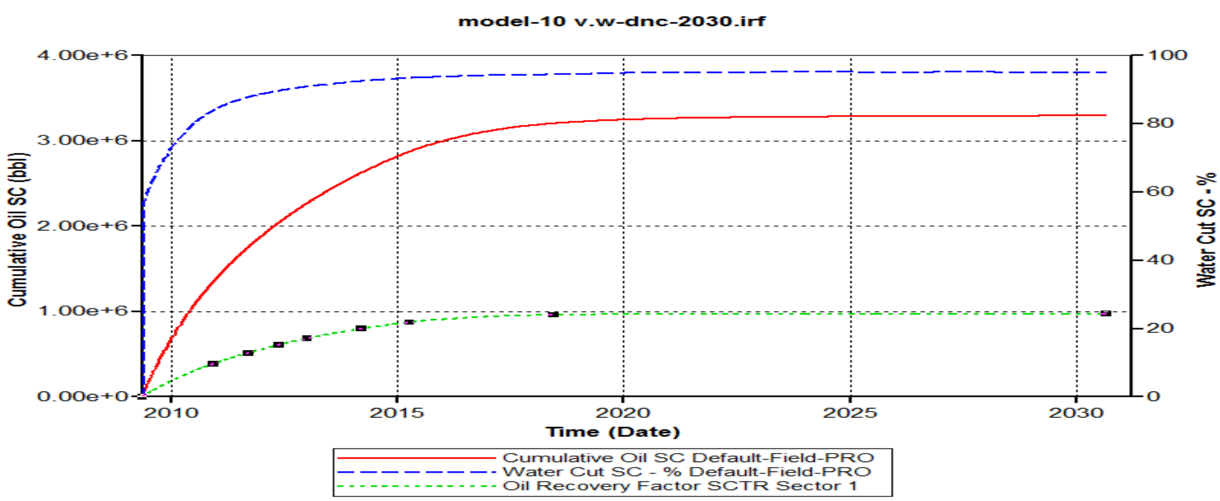

Figure. 5: Production Parameters for the Ten Vertical Wells

Location Sensitivity for horizontal wells

Simulation was run with ten horizontals wells located depending on oil saturation and porosity distribution. All the 10 wells have the same conditions length of horizontal section, production rate, and bottom hole pressure. Figure 6 shows the horizontal sections of the 10 wells, all wells have same lengthened of horizontal section.

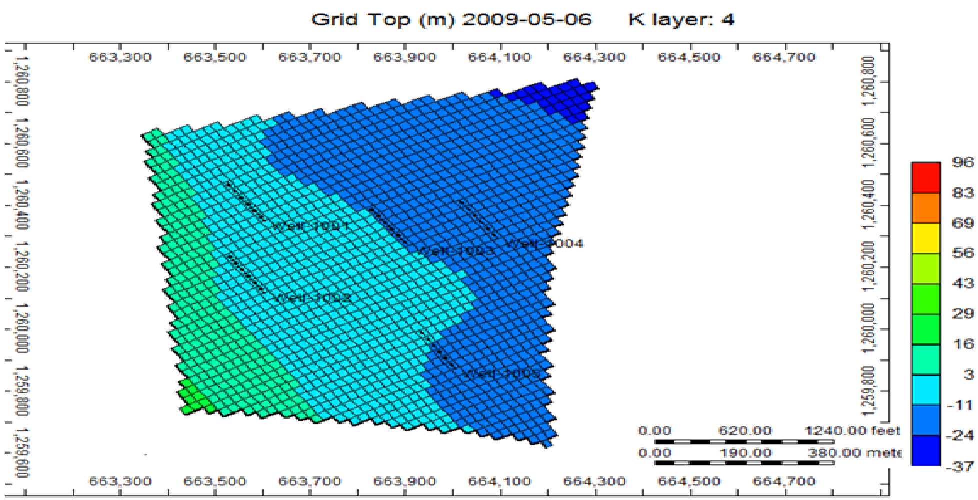

Figure. 6: Grid Top in 2D Show the Horizontals Section of Wells in Layer 4.

Simulation results for this case showed that the cumulative oil production for each well as shown in table 2, well-1005 and well -1003 have highest cumulative oil production which is 630175 bbl and 562313 bbl respectively.

Table (2): Cumulative Oil Production for the Ten Horizontal Wells case

	Well name	Cumulative oil, bbl
1	1001	444504
2	1002	447763
3	1003	567088
4	1004	553781
5	1005	633803
6	1006	290932
7	1007	326182
8	1008	231626
9	1009	566002
10	1010	417188

Length and Direction Sensitivity

The locations of Well 1005 and well -1003 were considered as the best location for the horizontal wells; however, the length of the wells and its directions are still challenging. 100M, 200M, 300M, 400M, 500M, 600M, 700M, and 800M were used as horizontal section lengths to study the effect of the well's length on cumulative oil production. The mentioned lengths were used in three directions including north, north-east, and east.

Well-1005: 18 models have been built to determine the best direction for well -1005 (all the results show in table 3. Simulation shows; the best incremental for north direction wells is in 600M with 342050 bbl cumulative oil produced, while the best incremental for north east direction is in 500M with 404570 bbl. The cumulative oil production increased more than any other length in north east direction at 400M. From the previous results for well-1005; the best direction is north east because it is more productive than any other directions and the best length is 500 because it has best incremental of cumulative oil with length.

Table (3): Incremental Cumulative Oil production for All the Direction for well-1005.

	Length (M)	Cumulative oil of North direction /E6 bbl	Incremental in oil with length /bbl	Cumulative oil of North east direction / E6 bbl	Incremental in oil with length /bbl	Cumulative oil of east direction /bbl	Incremental in oil with length /bbl
1	100	1.42116		1.39055		1.53043 E6	
2	200	1.43061	9450	1.5285	137950	1.59739 E6	66960
3	300	1.43671	6100	1.64087	112370		
4	400	1.49861	61900	1.89553	254660		
5	500	1.59525	96640	2.3001	404570		
6	600	1.9373	342050	2.43092	130820		
7	700	2.20265	265350	2.49184	60920		
8	800	2.31019	107540	2.52029	28450		

To determine the optimum length for well-1005, simulation was run with additional lengths including: 420M,450M ,480M 540 M, and 570 M, and cumulative oil productions has been checked for every run. 420 m was found to be the best length of horizontal section for well-1005 (table 4)

Table (4): Incremental in Cumulative Oil for Length between 400m and 600m for well-1005.

	Length(M)	Cumulative oil (E6 bbl)	Incremental in oil with length (bbl)
1	400	1.89553	
2	420	2.04021	144680
3	450	2.16496	124750
4	480	2.23065	65690
5	500	2.3001	69450
6	540	2.33568	35580
7	570	2.38347	47790
8	600	2.43092	47450

Well-1003: with the same procedure that mentioned in well-1005; 12 models has been built to find the best length and direction for well-1003. Simulation shows the best length for this well is 360M and the best direction is north. Table 5 and table 6 summarized the results.

Table (5): Incremental Cumulative Oil for All Direction for well-1003

	Leng th (M)	Cumulative oil of North direction /E6 bbl	Incremental in oil with length /bbl	Cumulative oil of North east direction /E6 bbl	Incremental in oil with length /bbl	Cumulative oil of east direction /E6 bbl	Incremental in oil with length /bbl
1	100	2.60494		2.31823		2.46803	

2	200	2.63152	26580	2.55337	23514	2.43045	-37580
3	300	2.63099	-530	2.56454	11170	2.40005	-30400
4	400	2.66448	33490	2.59666	32120	2.33196	-68540

Table (6): Incremental for Length between 400m and 600m for Well-1003

	Length(M)	Cumulative oil (bbl)	Incremental in oil with length (bbl)
1	300	2.63099 E6	
2	330	2.63433 E6	3340
3	360	2.65359 E6	18930
4	380	2.66088 E6	7290
5	400	2.66448 E6	3600
6	430	2.6641 E6	-380
7	460	2.66679 E6	3800

To find the total cumulative oil production, water cut, and the recovery factor using these two horizontal wells; simulation was run using 200 m3/day as production rate and 200 kPa as bottom hole flowing pressure for the two wells. The results showed that 3.9 MM bbl can be produced as cumulative oil production by year 2030, with 30.6 recovery factor and 91.2 % water cut (figure 7). Table 7 shows the comparison between the case of two horizontal wells and the 10 vertical wells mentioned in the first case.

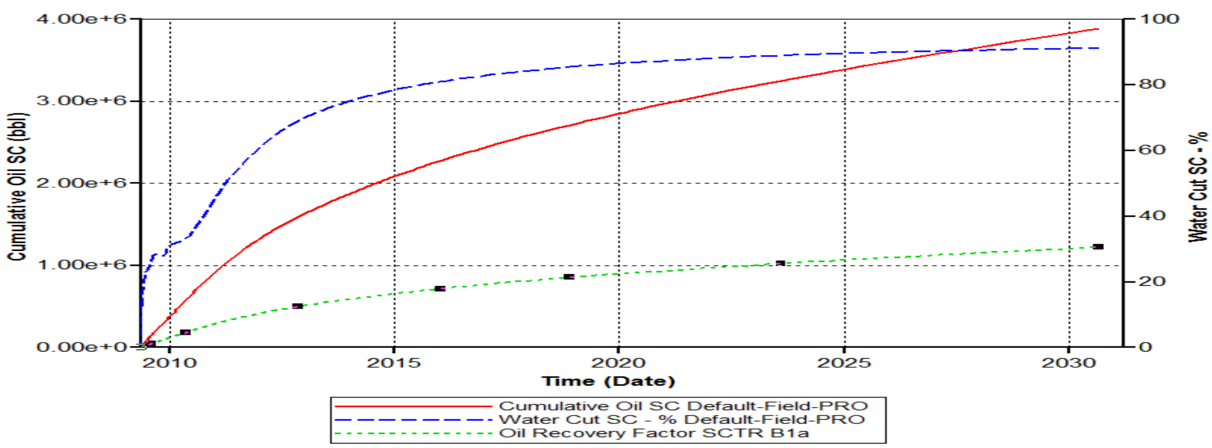

Figure. 7: The Two Horizontal Wells Field Cumulative Oil Production, Water Cut %, and Recovery Factor.

Table (7): Comparison between Ten Vertical Wells and Two Horizontal Wells

		Cumulative oil (bbl)	W.C(%)	RF (%)
1	Ten vertical wells	3.29346 E6	94.9 %	24.3 %
2	Two Horizontals Wells with Optimum Length and Direction	3.88241 E6	91.2 %	30.6 %

Optimization of Cyclic Steam Stimulation for the horizontal wells:

Many parameters for well-1005 and well-1003 has been changed to determine the best condition and best scenario. These parameters are: Temperature sensitivity, Quality of steam sensitivity, Injection rate sensitivity, Injection period sensitivity, Soaking period sensitivity. The same methodology has been used for the sensitivity analysis for both wells, and the results and detailed analysis has been provided.

Temperature Sensitivity: to find the optimum steam temperature; cumulative oil production from each well has been used as a parameter control for the best steam temperature. Simulation was run several times using different steam temperature ranges between 200-400º C while all the other parameters kept as constant. The results showed that the highest cumulative oil production can be achieved in 200-250º C steam T. The model has run again with different temperature values between 200-250º C to find the optimum steam temperature. From the results; the optimum steam temperature for well-1003 and well-1005 are 230º C and 330º C respectively, where 1.6334 and 1.26361 million bbl can be produced from the wells by the end of year 2030. Table 8 shows the cumulative oil production from well-1003 in different steam temperature as an example.

Table (8): Cumulative Oil Production for Different Steam Temperature (Well-1003)

	Temperature C°	Cumulative Oil Production, Well-1003(10^6 bbl)
1	200	1.63186
2	210	1.62979
3	220	1.63204
4	230	1.6334
5	240	1.62953
6	250	1.63032
7	300	1.62581
8	350	1.62427
9	400	1.61854

Steam Quality Sensitivity: 0.5-0.9 % steam quality has been tested to find the optimum steam quality for each well. Simulation run several times using different steam quality and the other parameters kept constant. Productivity was used as a control value for the results. The results showed that, the best steam quality is 0.8 % for the both wells where 2.17258×10^6 bbl and 2.58392×10^6 bbl can be produced from well-1005 and well-1003 respectively.

Steam Injection Rate Sensitivity: Steam injection rate is a factor controlling the volume of steam injected to the reservoir. In order to measure the steam injection rate, several values between 200-400 M3/day are used. In fact, high volume of steam injection cannot be a guarantee for more oil production (Seyed et al., 2017). 22 models have been run with different values of steam injection rate. The results showed that the differences of the cumulative oil production for 200 and 400 M^3/d steam injection is very small. From the simulation results; the best injection rate for well-1005 is 250 M3/day with (2176260 bbl) Cumulative oi production and the best injection rate for well-1003 is 200 M3/day with (2584920 bbl) Cumulative oil production

Steam Injection Period Sensitivity: 1- 35 days has been tested as steam injection period to achieve a high cumulative oil production. Ten's simulation run has been done to achieve the best injection period for every well. The results showed, the best injection period for well-1005 is 28 days with (2272550 bbl) cumulative oil production, and the best injection period for well-1003 is 3 days with (2634140 bbl) cumulative oil production. Well-1005 needed a long inaction period because it is length is 420 M in the north-east direction while the other well is only 360 M in one direction (North).

Soaking Period Sensitivity: to determine the optimum soaking periods for the both wells; the model run several times with different soaking periods between 1-20 days. 3 days has been found to be the optimum soaking periods for the both wells where, 2272550 bbl and 2634120 bbl cumulative oil production were achieved for well-1005 and well-1003 respectively by the end of year 2030.

Final Results of the optimum parameters of CSS in the two horizontal wells: After building and run more than 142 models; the optimum conditions for well-1005 and well-1003 are shown in table 9. Figure 8 show the cumulative oil production, water cut, and recovery factor for the field using two horizontal wells with CSS Where

4200880 bbl can be produced with 35.7 % recovery factor and 92.7 % water cut. Table 10 shows a comparison between the results from the 10 vertical wells, the two horizontal wells in the cold case, and the two horizontal wells in the CSS case. From the table; the incremental in the recovery factor is 47.5 % and 16.7 % compared to the 10 vertical cold wells and the two horizontal wells in the cold case respectively.

Table (9): The Optimum Parameters for Well-1005 and Well-1003 in CSS conditions.

	Well-1005	Well-1003
Length Of horizontal section(m)	420	360
Direction of horizontal section	North east	North
Temperature C	330	230
Steam quality %	0.8	0.8
Injection rate (M3/day)	250	200
Injection period (Days)	28	3
Soaking period (Days)	3	3

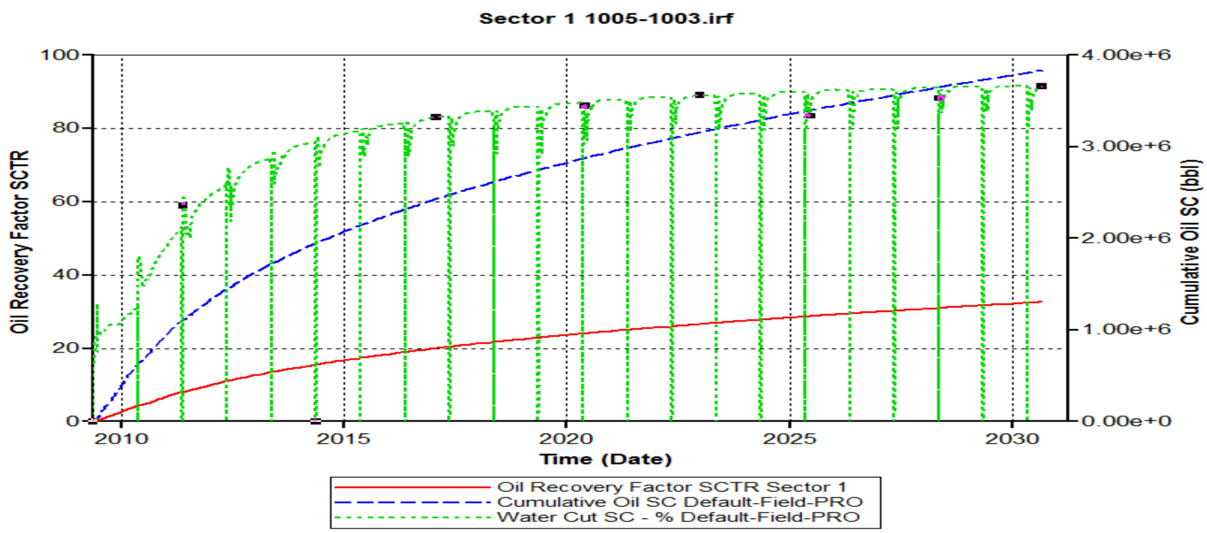

Figure. 8: Oil Recovery, Cumulative Oil and Water Cut.

Table 10: Comparison between vertical and horizontal wells in cold and CSS cases

	Ten vertical wells (cold case)	Two Horizontals Wells (cold case)	Two Horizontal Wells (CSS case)	Incremental of CSS horizonal wells with reference to the 10 vertical wells
Field Cumulative Oil (bbl)	329346 0	3882410	4200880	+27 %
W.C(%)	94.9	91.2	92.7	-2.3 %
RF (%)	24.3	30.6	35.7	+47.5 %

Conclusions and Recommendations

Two horizontal wells have been tested for Cyclic Steam Stimulation (CSS) to improve oil recovery using reservoir simulation modeling. From this study, horizontal well length and direction are strongly affecting the cumulative oil production. The optimum length of horizontal section for well -1005 and well-1003 are 420 m and 360 m in north-east and north directions respectively. The optimum CSS parameters may vary according to the well location and reservoir heterogeneity. In this study; 230º C, and 330º C are the steam temperature; 250 M^3/d, 200 M^3/d are the steam injection rate; 28 days, 3 days are the injection period for well-1005 and well-1003 respectively. Simulation showed that the two wells have the same steam quality (80%), and soaking periods (3 days). From the results; the recovery factor can be increased by 47.5% using the two horizontal wells compared to 10 vertical cold wells, while the cumulative oil production has been increased by 27% with reduction of 2.3 % water cut. An economical evaluation is highly recommended for drilling the horizontal wells and CSS implementation.

References:

Ahmed, T (2010). Reservoir engineering handbook, 4th edition. Huston: Gulf Professional Publishing.

E. Escobar, P. Valkó, W. J. Lee, M.G. Rodríguez, (2000). Optimization Methodology for Cyclic Steam Injection with Horizontal Wells. SPE/Petroleum Society of CIM 65525, Calgary, Alberta, Canada.

Elbaloula, H., Pengxiang, H., Elammas, T., Alwad, F., Rdwan, M., Musa, T. (2016). Designing and Implementation of the First Steam Flooding Pilot Test in Sudanese Oil Field and Africa, Society of Petroleum Engineers, SPE Kingdom of Saudi Arabia Annual Technical Symposium and Exhibition, 25-28 April, Dammam, Saudi Arabia doi:10.2118/182790-MS

Elbaloula, H.A., Jin'e, C., Zichang, T. et al. (2020). Feasibility Study and Numerical Simulation to Design the Steam Flooding Pilot Test Patterns. J Petrol Explor Prod Technol 10, 2559–2573 (2020). https://doi.org/10.1007/s13202-020-00879-4.

H. Mendoza, A. Padron and F. Portillo (1997). Steam Stimulation in Horizontal Wells Pilot Test in Venezuela. Petroleum Society of Canada, Calgary.

Husham Elbaloula, Tagwa Musa (2019). Implementation of Cyclic Steam Stimulation to Enhanced Oil Recovery for a Sudanese Oil Field, SUST Journal of Engineering and Computer Sciences (JECS), Vol. 91, No.2, 8192.

James J. Sheng (2013). Cyclic Steam Stimulation (chapter 16), Enhanced Oil Recovery Field Case Studies, Gulf Professional Publishing, 2013, Pages 389-412, https://doi.org/10.1016/B978-0-12-386545-8.00016-6.

Seyed Ali Razeghi, Vladimir Mitrovic, Solomon Adjei Marfo (2017). The influence of steam injection for Enhanced Oil Recovery (EOR) on the quality of crude oil, Petroleum Science and Technology, 35:13, 1334-1342, DOI: 10.1080/10916466.2017.1327970.