Feasibility study and numerical simulation to design the steam flooding pilot test patterns

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Abstract

Steam flooding is a method of injecting steam to heat the oil and decrease its viscosity so that it will be easy to flow from injector to producer. Fula North East oil field is a massive edge and bottom water reservoir with good properties and high viscosity of crude oil. As of March 2018, the oil field has been fully commissioned in steam stimulation for 3 years and the water cut rises rapidly and the oil rate declines seriously. In this paper, through comprehensive analysis of the geological properties of reservoir, production dynamics of single well and cement quality of wellbore, the steam flooding pilot test area under different well groups is screened out. Advanced thermal enhanced oil recovery simulator has been used to build the model of 279, 888 cells to design and optimize steam flooding pilot area for this field. The best well space and development program are optimized; this paper supplies a theoretical foundation for the next step of steam flooding in the whole field. The results show that the optimum steam flooding parameters for this area are steam injection temperature of 270 °C, with 5–7 MPa injection pressure, steam injection quality of more than 0.6 and steam injection rate of 1.6 m³/day/ha/m, and the final recovery ratio will reach 32.3%.

Keywords Numerical simulation · Thermal EOR · Steam flooding Sudanese oil fields

List of symbols

%	Percentage
AG	Abu Ghabra
B1a	Bentiu 1a
B1a + b	Bentiu 1a + Bentiu 1b
Bbl	Barrel
Bbl/day	Barrel per day
cP	Centipoise
CAPEX	Capital cost
CSS	Cyclic steam stimulation
Cum.	Cumulative
DNC	Do-nothing case
DX	Dimension in X-direction
DY	Dimension in Y-direction
DZ	Dimension in Z-direction
E&P	Exploration and production

EA	Areal sweep efficiency
ED	Displacement efficiency
EOR	Enhanced oil recovery
EV	Vertical sweep efficiency
FNE	Fula North East
IRR	Internal rate of return
kJ/kg	Kilojoule per kilogram
M ³	Cubic meter
m ³ /day m	Cubic meter per day per meter
m ³ /day	Cubic meter/day
m ³ /day/ha/m	Cubic meter per day per hectare per meter
Max	Maximum
mD	Meli Darcy
Min	Minimum
MM\$	Million dollars
MMm ³	Million cubic meter
MMSTB	Million stock tank barrel
MOPM	Ministry of Petroleum and Mining
MPa	Megapascal
NP	Cumulative oil produced
NPV	Net present value
NS	Initial oil in place at the start of the flood
°C	Degree Celsius
OEPA	Oil Exploration and Production Authority

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OPEX	Operating cost
OSR	Oil–steam ratio
PE	Petro-energy
Pi	Initial pressure
Pro.	Production
Psi	Pound-force per square inch
RF	Recovery factor
SF	Steam flooding
SF#2	Steam flooding phase number two
SPE	Society of Petroleum Engineering
STB	Stock tank barrel
US	United States
WIT	Water injection total

Introduction

Thermal enhanced oil recovery (TEOR) is a family of tertiary 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 methods of EOR entail the application of heat to the oil well. Thermal methods have been tested since 1950s, and they are the most advanced among EOR methods, as far as field experience and technology are concerned. They are best suited for heavy oils (10–20° API) and tar sands ($\leq 10^\circ$ API). They have the ability to lower the viscosity of the oil and thus increase the mobility ratio. These methods are typically employed in relatively shallow oil wells with higher viscosity such as tar sands and heavy oil. Thermal methods of EOR have been highly successful in the USA, Canada, Venezuela and Indonesia and have also been used in China and Brazil. Within the USA, thermal methods account for around 40% of EOR production (Prats 1982).

Types of thermal EOR

- Steam flooding.
- Cyclic steam stimulation (CSS).
- Steam-assisted gravity drainage (SAGD).
- In situ combustion (ISC).
- Solar EOR.
- Electro-EOR (EEOR).
- Heated annulus steam drive (HASD).
- Steam and solvent processes.

FNE field is located about 9 km away from the North East of Fula field in Fula Sub-basin in Sudan; it is structurally subdivided into three main blocks, which are FNE-1, FNE-3 and FNE-N. There are three proved hydrocarbon-bearing formations (Aradaiba, Bentiu and AG), among which Bentiu is the main pay zone. Figure 1 shows the location of FNE.

Fig. 1 FNE location map (Elbaloula et al. 2016)

FNE oil field is considered as heavy oil field and it has shallow reservoir, and Bentiu reservoir is affected by strong bottom water. The reservoir of FNE oil field is characterized by normal temperature and pressure system at 529 m depth. The average pressure is 576 psi and the average temperature is 43.9 °C. FNE has conventional heavy oil in both Aradaiba and Bentiu, and Bentiu reservoir has a relatively good quality with porosity ranging from 17 to 40%, permeability ranging from 100 to 11000 mD and viscosity of about 840 cP (Elbaloula et al. 2016).

The oil field put into production in 2010 with cold production and cyclic steam stimulation. By March 2018, a total of 117 wells had been drilled, including one horizontal well; 116 wells have been put into operation, of which 21 wells are producing as cold, 82 wells for steam stimulation and 13 wells for steam flooding. One hundred and eleven wells were opened with a daily oil production of 489 bbl, a daily fluid production of 10,145 bbl, water cut of 54%, the total original oil in place of 332MM STB, and the up-to-date recovery factor of reservoirs of 0.8%.

Literature review and screening

Years of production shows that the daily oil production for steam stimulation is almost three times of the cold wells, indicating that injection steam into well bottom can heat the reservoir and reduce viscosity of the heavy oil to increase production capacity. Currently, the oil fields used for steam flooding include China's Liaohe oil field, US Kern River oil field, Indonesian Dori oil field and so on (Jones et al. 1995).

From screening, the Qi 40 of Liaohe oil field which put into steam flooding has been selected early as a reference example to illustrate the feasibility of steam flooding in FNE oil field. Qi 40 reservoir was put into operation in 1983 by steam stimulation with oil take-off rate of 15.3%. During

Table 1 Reservoir properties of each oil field using steam flooding (Elbaloula et al. 2016; Pearce and Megginson 1991; Jones et al. 1995; Taber et al. 1997)

Item	Qi 40	Shu175	Wa 38	Cruse E	Kern River	FNE	SPE (Taber)
Reservoir type	Tectonic–lithology with edge–bottom water	Tectonic–lithology with edge–bottom water	Sand with good connectivity	Sand with good connectivity	Sand	Tectonic–lithology with bottom water	
Depth (m)	625–1025		1240–1430	548		543	< 1524
Net pay (m)	37.7	47.8	21.5	36.6	29.5	44	> 6
Pi (psi)	1232.5	1508	435–580			564	
T (°C)	36.8	55				44	
Porosity (%)	31.5	25.6	22.3			32	
Permeability (mD)	2062	1500	1066			3200	> 200
Viscosity@50 °C (mPa s)	3100–4600	10,000	15,000			712–2543	< 100,000
Well pattern	Anti-9		Anti-9	Anti-5	Anti-9	Anti-5	
SF period recovery (%)	20.9–37.4	23.4			37	Study > 20	

the period of 1990–2000, the steam flooding test was carried out. In 2001, intermittent steam flooding was officially started. The well pattern was anti-9 spot with well space of 100 meters. As of December 2003, the oil take-off rate increased to 41.4%, highlighting the superiority of steam flooding for heavy oil reservoirs (Jiu-quan et al. 2006).

By comparing the reservoir properties for each oil field and the applicability of steam flooding and comparing SPE table for EOR screening (Taber et al. 1997), as given in Table 1, it is considered that the Sudan FNE oil field is suitable for steam flooding, and this paper well covers the steam flooding screening, pilot area selection, pilot simulation and designing as well as optimization.

Methodology

The geological data, reservoir data and production data for FNE oil field have been collected and used for analysis to identify the situation of the field, and it is suitable for conducting steam injection and full-field implementation.

Advanced thermal EOR simulator software has been used to build the dynamic model and to design and optimize steam flooding injection and production parameters for FNE oil field.

The steps in Fig. 2) are used in this paper.

Results and discussion

The thermal recovery is essential for this field, and the first pilot has been conducted in FNE-16 well and the results showed that the CSS has the ability to double the production,

Fig. 2 The steps and workflow for this study

and then, additional wells have been added at each phase. Up to 2016, the total CSS wells are 67 including 37 wells are under the first and second cycles, 24 wells under the third and fourth cycles and 6 wells under the fifth cycle.

The average daily oil production for this field has been increased from 5300 bbl./day as of December 2014 to 8300 bbl./day as of September, 2016, and the peak oil production has been recorded in 2016 as 9000 bbl./day. The CSS is very successful, and the average oil rate is almost 1.6 times compared to cold production. The CSS only can increase the recovery percent from 32.5 to 34.2%, which makes it more attractive as development scenario for FNE oil field (Elbaloula 2017).

The steam flooding pilot has been implemented in September 2015, and the results encourage to go for the second steam flooding pilot in this field in order to get full picture of full-field implementation as given in Table 2.

Table 2 Screening criteria for thermal recovery and development (Elbaloula et al. 2016)

Item	CSS	SF	FNE
Pay depth (m)	< 1700	< 1300	550
Pay thickness (m)	10–35	7–60	30
NTG	0.35	> 0.4	0.6
Horizontal perm. (md)	> 200	> 200	4000
Porosity %	> 20	> 20	32
Oil saturation %	> 60	> 45	70
Dead oil viscosity, mPa s	/	< 10,000	661 (50°)
Reservoir pres (Psi)	< 1885	< 725	610

Pilot area selection analysis

In order to select the best location for pilot, screening of FNE oil field with steam flooding has been conducted; the following factors are considered:-

1. The pilot area must have abundant reservoir resources, and then, the properties can represent the general level of the whole oil field.
2. The sand body between the producer and the injector must have good connectivity and a uniform oil–water contact, and the interlayer should be fully considered to make sure that the injected steam plays a more desirable role.
3. At present, the daily oil production of some wells is in a decreasing stage, and the water cut is relatively high.

Dynamic analysis needs to be conducted to assist optimization.

4. The producers have experienced at least one cycle of high-temperature steam injection and soaking, and even four–six cycles. The cementing facility of some wells becomes damaged. Therefore, it is necessary to check the well cementing and propose workover before steam flooding.

Block 1 is located at a high structure with 16 wells, including 2 cold wells and 14 steam simulation wells. Two cold wells and three CSS wells were put into production in 2010 and 11 steam simulation wells in 2015. The main perforation layers are B1a and B1b. Block 2 is located in a relatively low structure with 11 wells, including three cold wells commissioned in 2010 and eight steam wells commissioned in 2015.

According to above screening principle and considering the block structure, the effective thickness of the reservoir (Fig. 3), the cementing quality and the current production status, the selected block 1 is selected as the steam flooding pilot area to carry out the next numerical simulation and development plan prediction.

Building the numerical model

Advanced thermal process reservoir simulator has been used which includes options such as chemical/polymer flooding, thermal applications, steam injection, horizontal wells, dual

Fig. 3 Reservoir properties and pilot area

Fig. 4 3D view of porosity distribution and wells location in FNE oil field

porosity/permeability, directional permeability, flexible grids, fireflood and many more.

The pilot area has been cut as sector model from static model and then used for initialization, history matching and prediction using advanced thermal EOR simulator. The grid number of model is $49 \times 48 \times 119 = 279,888$, cell size is $dx = dy = 20$ m, $dz = 1$ m, and vertical formation includes Ara-D, AE, AF, B1a, B1b, B1c, B1d and B1e. Figure 4 shows 3D view of porosity distribution and wells location in FNE oil field.

After finding the difference between calculated production and observed production, some parameters of the dynamic model are modified. The process is continuous in order to make dynamic model match closely to the actual reservoir performance and ensure the reliability of the remaining oil distribution.

History matching

During history matching of oil field, the matched parameters are pressure, liquid rate, oil rate and water cut. The reservoir pressure and production of the field were firstly matched. Then, the flowing bottom-hole pressure and production of single well were matched (Fig. 5).

For the history matching result, 10 wells taking 50 percent of SF2 pilot area are well matched, 5 wells are fairly matched and 1 well is poorly matched. The history matching fitting rate is 94%.

Scenarios design for pilot test well group

Essentially four types of well arrangements are used in fluid injection projects:

1. Irregular injection patterns.
2. Peripheral injection patterns.
3. Regular injection patterns.
4. Cristal and basal injection patterns.

A wide variety of injection–production well arrangements have been used in injection projects. The most common patterns, as shown in Fig. 6, are the following (Ahme 2018):

- Direct line drive.
- Staggered line drive.
- Five spots.
- Seven spots.
- Nine spots.

In terms of cumulative oil production, Eq. 1 can be written as:

$$NP = NS \text{ ED EA EV} \quad (1)$$

Applying the above methods for this field, it has been found that totally four different well groups including 5 spots, 7 spots and 9 spots can be optimized (Fig. 7). In these cases, liquid rate is the last point of time; injection rate is

Fig. 5 History matching result of block and single well

Fig. 6 Flood patterns (Ahme 2018)

100 m³/day. For the forecast result, taking the new wells needed and economic condition into account, option 3 (7 spots) including 6 new producers is recommended in this case (Table 3).

Optimization

The optimization is done for the injection parameters such as injection rate, injection volume, injection pressure and temperature, also for the timing of converting from CSS to steam flooding besides the production parameters as well.

Timing of converting to steam flooding

There are four cases designed in order to know the timing of converting to steam flooding in this pilot area, including converting in January 2020, January 2021, January 2022 and January 2023. For the forecast result of these four cases, the oil recovery factor decreases along with the converted timing delay (Table 4, Fig. 8). Based on the temperature distribution in 2020 and 2021, the heat connectivity is already formed and most of the wells are in the fourth cycle until January 2020. According to experience of SF#1 block,

Fig. 7 Steam flooding well group options **Table 3** SF designed and forecast result of each option

No.	Well pattern	Injection timing	New well	Cum. oil (MMstb)	WIT (MMm ³)	RF (%)	Comment
1	5	2018.10	14	8.23	3.54	27.6	11 new injectors, 3 new producers
2	5	2018.10	2	7.18	2.67	23.9	4 producer well convert to injector, 2 new producers
3	7	2018.10	6	8.18	2.59	27.3	4 producer well convert to injector, 6 new producers
4	9	2018.10	8	8.57	2.59	28.6	3 producer well convert to injector, 1 new injector, 7 new producers

SF#2 pilot area could be converted for steam flooding in January 2020.

Liquid rate and injection rate

In this case, the producers' product intensity is 5–40 bbl/day m according to the production history of each well and the injector's injection index is 20–70 bbl/day m same as

SF#1 (Tables 5, 6). Based on reasonable liquid–steam ratio which ranges from 0.8 to 2.0, ten cases are selected for optimization (Table 7).

For the forecast result of these ten cases, the oil recovery factor is increasing progressively along with the injection rate increasing (Table 8). Boiler condition is as follows: Steam outlet temperature is 300 °C, boiler efficiency is 88%, and if not considered the heat loss, the enthalpy of oil

Table 4 Forecast index of converting to SF timing cases

Item	Case 1	Case 2	Case 3	Case 4
Converted timing	2020/01	2021/01	2022/01	2023/01
Ave. cycle	5	6	7	8
Cum. liquid (MMB)	21.93	21.34	20.74	20.12
Cum. oil (MMB)	8.26	8.14	8.03	7.91
Cum. injection (MMm ³)	2.46	2.33	2.22	2.10
Water cut (%)	79.34	79.53	79.44	77.68
RF, Bentiu (%)	27.80	27.36	26.97	26.57

Fig. 8 Cumulative oil and injection steam along with injection timing delay**Table 5** Summary of product intensity for producers

Well	Net pay m	Liquid rate of history			Product intensity
		Min (bbl/ day)	Max (bbl/ day)	bbl/day m	
FNE-2	14	87	158	6.4	11.5
FNE-5	14	58	300	4.1	21.1
FNE-12	15	55	195	3.7	13.2
FNE-16	17	58	600	3.4	35.1
FNE-17	17	68	670	4.1	40.3
FNE-18	15	74	586	5.0	39.4
FNE-23	10	63	344	6.2	34.0
FNE-56	11	52	470	4.7	42.7
FNE-69	23	97	475	4.3	20.9
FNE-70	12	160	360	13.3	30.0
FNE-71	10	165	285	16.5	28.5
FNE-73	12	75	350	6.2	29.0

is 41900 kJ/kg. Enthalpy of saturated steam under 300 °C is 2750 kJ/kg, which means 0.5 barrel oil exchanges 1 m³ steam. For example, compared with case 6, case 10 needs to spend 0.65 MMB oil to get 1.3 MMm³ steam. Considering the economic problem (water cut 98%), case 10 needs to get net oil at least 0.276 MMbbl. So it needs to add oil

Table 6 Summary of injection index for injectors of SF#1

Well	Net pay m	Liquid rate of history			Injection intensity
		Min (bbl/day)	Max (bbl/day)	bbl/(day m)	
FNE-50	21	445	742	21.2	35.3
FNE-51	16	490	819	30.6	51.2
FNE-52	16	387	900	24.2	56.3
FNE-53	15	379	1024	25.3	68.3

0.926 MMstb totally; however, it only needs to add oil 0.73 MMbbl (Table 9).

In conclusion, the liquid rate and injection rate of case 6 are chosen, producers' product intensity is 20 bbl./day m per well, steam injection index is 7 m³/day m per well, and the average injection rate is 96 m³/day per well.

Steam quality and steam temperature

There are totally 18 cases in this case, and the steam quality of injectors ranges from 0.6 to 0.9 and temperature ranges from 200 to 340 °C (Table 10). According to the forecast result, recovery factor of each case is different, but the difference is very small (Table 11). Taking the rationality of steam temperature and quality into consideration, the current case (case 8) is chosen although the recovery factor of case 12 is the highest.

SG intermittent open

There are totally 18 cases in this case, and the SG stop time ranges from 1 to 4 weeks and SG open time ranges from 1 to 6 weeks (Table 12). According to the forecast result, recovery factor of case 15 (open 6 weeks and stop 1 week) is the highest, but the value of current case (no stop) is higher (Table 13). Finally, the current case (no stop) could be kept.

Product layer and injection layer

There are totally 15 cases in layer optimization case, and oil zones include B1a, B1b and upper B1c (Table 14). There

Table 7 Liquid rate and injection rate of each well in selected ten cases

No.	Liquid rate (bbl/day)										Injection rate (m ³ /day)							
	FNE-2	FNE-5	FNE-12	FNE-16	FNE-17	FNE-18	FNE-23	FNE-56	FNE-69	FNE-70	FNE-71	FNE-73	New well	FNE-64	FNE-66	FNE-86	FNE-87	
1	69	71	74	86	83	74	51	55	114	60	50	60	70	29	39	56	51	
2	137	142	147	171	166	149	101	110	227	120	100	121	141	43	58	84	76	
3	137	142	147	171	166	149	101	110	227	120	100	121	141	57	78	112	101	
4	137	142	147	171	166	149	101	110	227	120	100	121	141	63	86	123	112	
5	137	142	147	171	166	149	101	110	227	120	100	121	141	72	97	140	127	
6	274	284	295	342	332	298	202	220	454	240	200	242	282	63	86	123	112	
7	274	284	295	342	332	298	202	220	454	240	200	242	282	72	97	140	127	
8	274	284	295	342	332	298	202	220	454	240	200	242	282	86	116	168	152	
9	274	284	295	342	332	298	202	220	454	240	200	242	282	100	136	195	178	
10	407	424	439	510	495	444	301	328	677	358	298	360	420	100	136	195	178	

is no clear interbred between B1a and B1b in the sector model also (Figs. 9, 10), and the wells grouping has been selected as shown in Fig. 11. The shale barrier has three types including clear shale barrier, thin shale barrier and no clear shale barrier after checking the logging interpretation result (Figs. 12, 13, 14). So case 12 was designed to simulate this situation, in which wells' perforation has three types (Table 15). Wells with clear shale barrier perforate B1a and B1b. Wells with thin shale barrier perforate B1a and upper B1b. Wells with no clear shale barrier perforate B1a. Some wells need to adjust perforation based on actual production situation such as FNE-5 and FNE-73.

According to the forecast result, the recovery factor of case 12 is the highest, 1% enhanced by the case with current perforation (Fig. 15). Case 12 for the shale barrier is recommended.

Converting time from CSS to SF

There are many reasons to convert CSS to SF such as changes in the temperature, pressure, and saturation of the well group, and from the previous study for this field and from numerical simulation results for turning to steam flooding and after comparing recovery percent of reservoirs, switching to steam flooding after the second period of steam stimulation is also the best (Elbaloula et al. 2016).

Considering the previous studies and experience of CSS implementation in FNE oil field, the assumption for the simulation was to start the SF as soon possible since most wells has more than two CSS cycles and many wells start production with CSS at different times.

Final results

Base on the above optimized result, FNE-03 block SF#2 pilot area can choose 7 spots with 6 new producers and 4 wells converting to injectors in January 2020 (18producers + 4 injectors). In the recommended case, the producers' production intensity and injectors' injection index are 20 bbl/day m and 7 m³/day m, respectively (Tables 16, 17). Steam quality and temperature need to maintain current situation of 0.7 and 270 °C, respectively. The SG should not stop to inject steam, and considering shale barrier when adding new perforation is necessary.

For the recommended case forecast result, by the end of 2035, cumulative oil is 9.69 MMbbl, oil recovery factor of Bentiu is 32.3% enhanced by 15% compared with do nothing case (Tables 18, 19 and Fig. 16). Compared the optimized oil rate and liquid rate in the recommended case with the actual current data (May. 2018), the production performance will be greatly improved. Also Aradaiba D formation can consider for future production and could get additional cumulative oil of 1.47 MMstb.

Table 8 Liquid rate and injection rate of each well in selected ten cases

Item/case	1	2	3	4	5	6	7	8	9	10
Cum. liquid (MMB)	12.0	19.4	19.4	19.4	19.5	33.7	33.7	33.9	34.0	47.5
Cum. oil (MMB)	6.22	7.60	7.83	7.94	8.03	8.81	8.93	9.14	9.29	9.54
Cum. injection (MMm ³)	1.14	1.65	2.14	2.37	2.67	2.37	2.67	3.17	3.67	3.67
RF, Bentiu (%)	20.91	25.55	26.32	26.70	27.00	29.63	30.05	30.77	31.27	32.12
OSR	0.87	0.73	0.58	0.53	0.48	0.59	0.53	0.46	0.40	0.41

Table 9 Liquid rate and injection rate of each well in selected ten cases

Item	Case 6	Case 7	Case 8	Case 9	Case 10
Cum. liquid (MMB)	33.7	33.7	33.9	34	47.5
Cum. oil (MMB)	8.81	8.93	9.14	9.29	9.54
Cum. injection (MMm ³)	2.37	2.67	3.17	3.67	3.67
Add. inj. (MMm ³)		0.3	0.8	1.3	1.3
Fuel oil (MMB)		0.15	0.4	0.65	0.65
Add. oil (MMB)		0.12	0.33	0.48	0.73
Add. fluid (MMB)		0	0.2	0.3	13.8
98% oil (MMB)		0	0.004	0.006	0.276
Net oil (MMB)		−0.03	−0.074	−0.176	−0.196

Table 10 Steam quality and seam temperature optimization cases

Case no.	Steam quality	Temperature
1	0.6	200
2	0.6	230
3	0.6	270
4	0.6	300
5	0.6	340
6	0.7	200
7	0.7	230
8	0.7	270
9	0.7	300
10	0.7	340
11	0.8	200
12	0.8	250
13	0.8	300
14	0.8	340
15	0.9	200
16	0.9	250
17	0.9	300
18	0.9	340

Table 12 SG open and stop times optimization cases

Case no.	Injection time Week	Stop time Week
1	1	1
2	2	1
3	2	2
4	3	1
5	3	2
6	3	3
7	4	1
8	4	2
9	4	3
10	4	4
11	5	1
12	5	2
13	5	3
14	5	4
15	6	1
16	6	2
17	6	3
18	6	4

Table 11 Forecast result of steam quality and steam temperature optimization cases

Case	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Cum. liquid (MMB)	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6	33.6
Cum. oil (MMB)	8.49	8.56	8.64	8.67	8.70	8.70	8.75	8.83	8.84	8.81	8.91	8.91	8.93	8.92	9.03	9.06	9.04	8.96
Cum. injection (MMm ³)	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37
RF, Bentiu (%)	28.7	28.9	29.2	29.3	29.4	29.4	29.6	29.8	29.9	29.8	30.1	30.1	30.2	30.1	30.5	30.6	30.6	30.3

Table 13 Forecast result of SG open and stop time optimization cases

Case	No stop	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Cum. liquid (MMB)	33.6	32.3	32.9	32.2	33.1	32.6	32.2	33.2	32.9	32.5	32.2	33.3	33.0	32.7	32.5	33.3	33.1	32.9	32.6
Cum. oil (MMB)	8.83	7.94	8.23	7.96	8.36	8.16	8.01	8.44	8.26	8.13	8.01	8.49	8.32	8.23	8.14	8.55	8.37	8.27	8.20
Cum. injection (MMm ³)	2.37	1.19	1.54	1.19	1.72	1.4	1.19	1.82	1.54	1.34	1.19	1.89	1.64	1.45	1.31	1.95	1.71	1.54	1.40
RF, Bentiu (%)	29.8	26.7	27.7	26.8	28.1	27.4	27.0	28.4	27.8	27.4	26.9	28.6	28.0	27.7	27.4	28.8	28.2	27.8	27.6

Table 14 Product layer and injection layer optimization cases

Case no.	Product layer	Injection layer
1	1a	1a
2	1b	1b
3	1a 1b	1a 1b
4	1a 1b	1a
5	1a 1b	1b
6	1a 1b 1c	1a
7	1a 1b 1c	1b
8	1a 1b 1c	1a 1b 1c
9	1a 1b	1a 1b 1c
10	1a 1c	1a 1b 1c
11	1b 1c	1a 1b 1c
12	1a, 1a&1b and 1a&upper 1b	1a&1b and 1a&upper 1b
13	1a 1b 1c	1a 1b
14	1a 1b 1c	1a 1c
15	1a 1b 1c	1b 1c

Fig. 9 Well type distribution

Economic evaluation

Although this work is a scenario-based optimization, simple economic evaluation model has been done for this research in order to fully picture the feasibility study of steam flooding in this area, and the assumptions for the sensitivity analysis are as follows:

Fig. 10 Net gross of (B1a and B1b) layers **Fig. 11** Well group map

Evaluation period is 2016–2027, under the oil price of 50\$/bbl, we do the IRR sensitivity analysis of Contractor, and the variation scopes are 10% and 20%, and the detailed sensitivity analysis results are given in Table 20 and Fig. 17.

From sensitivity analysis, the oil price is the most sensitive factor. When the oil price decreases 20%, the IRR is 12.85% still greater than 10%, which means the contractor has the strong ability to resist risks, and under the present oil price, the contractor is profit.

Fig. 12 Sand section around FNE-66

Fig. 13 Sand section around FNE-64 and FNE-66

Also when the oil price is 40\$/bbl, the IRR of the four basic cases is 32.45%, 31.48%, 25.12% and 32.47%. The state NPV of the four basic cases is 153.85 MM\$, 208.29 MM\$, 206.43 MM\$ and 212.46 MM\$, and in all of the cases except DNC case, from the sensitivity analysis, the oil price got the highest sensitivity of IRR, in the break-even point, the oil price is 34.78\$/bbl of recommended case, all the cases are profit, but we still should pay more attentions to the international oil price to avoid investment risks.

Conclusions and recommendation

- The feasibility study to design the second steam flooding pilot test patterns in Sudanese oil field has been done, and the pilot area has been selected and designed using advanced thermal EOR simulator.
- After the analogy with the development effect of similar international oil fields, combined with international standards for thermal recovery, the preliminary result from the screening shows that FNE oil field is suitable for steam flooding.
- According to the geological and dynamic facts of FNE oil field, the steam flooding pilot test area and well groups have been selected in FNE-03 block SF#2 pilot area and the optimized result to choose 7 spots with 6 new producers and 4 wells to be converted to injectors in 2020.
- The results show that the optimum steam flooding parameters for this area are steam injection temperature of

Fig. 14 Sand section around FNE-86 and FNE-87

Table 15 Perforation of each well in Case 12

Case 12	Clear shale barrier						Thin shale barrier					No clear shale barrier				
	FNE-2	FNE-5	FNE-16	FNE-64	FNE-66	FNE-73	FNE-17	FNE-23	FNE-56	FNE-86	FNE-87	FNE-12	FNE-18	FNE-69	FNE-70	FNE-71
Layer	B1aB1b						B1a, upper B1b					B1a

Fig. 15 Recovery factor curve of each case

Table 16 Liquid rate of producers in recommended case

Well	FNE-2	FNE-5	FNE-12	FNE-16	FNE-17	FNE-18	FNE-23	FNE-56	FNE-69
Interval	523–548	503–528	518.5–529	523–562	515.5–549	536–553	521–555	538–568	518.5–537
Layer	B1aB1b	B1a	B1a	B1aB1b	B1aB1b	B1a	B1aB1b	B1aB1b	B1a
Rate, bbl/day	364	284	247	412	412	298	332	290	454
Well	FNE-70	FNE-71	FNE-73	W7-1	W7-2	W7-3	W7-4	W7-5	W7-6
Interval	536–537	539–549	531–547	504–546	514–558	518–562	508.5–550.5	534–559	522.5–553
Layer	B1a	B1a	B1a	B1aB1b	B1aB1b	B1aB1b	B1aB1b	B1a	B1aB1b
Rate, bbl/day	280	200	242	315	315	315	315	252	283

Table 17 Injection rate of injectors in recommended case

Well	FNE-64	FNE-66	FNE-86	FNE-87
Interval	514–553	524–566	534.5–560	524–555
Layer	B1aB1b	B1aB1b	B1aB1b	B1aB1b
Rate, m ³ /day	87	98	148	143

270 °C, with 5–7 MPa injection pressure, steam injection quality of more than 0.6 and steam injection rate of 1.6 m³/day/ha/m, and the final recovery ratio will reach 32.3%.

- The optimum production rate for producers is 20 bbl/day m and for injectors' injection index is 7 m³/day m).
- From simple economic analysis, the IRR for the recommended case is 32.47%, NPV is 212.46 MM\$, and in the break-even point, the oil price is 34.78\$/bbl.
- It is highly recommended for this area to convert from CSS to steam flooding producing in 2020 in order to produce high recovery factor, and it is necessary to consider shale barrier when adding new perforation.
- It is strongly recommended to conduct detail economic evaluation for this area for field implementation.

Table 18 Forecast result of DNC and recommended case

Case	Cum. liquid (MMB)	Cum. oil (MMB)	Cum. injection (MMm ³)	Water cut (%)	Production–injection ratio	RF (Bentiu) (%)
DNC	12.5	5.12	0.37	81.1	4.2	17.0
Recommended case	36.8	9.69	2.90	89.0	2.0	32.3

Table 19 Recommended case development indicator prediction

Date	Oil well	Inj. well	Pro. daily/effect well			Pro. daily/all well			Pro. yearly			OSR	Cum				RF
			Oil	Liquid	steam	Oil	Liquid	steam	Oil	Liquid	steam		Oil	Water	Liquid	steam	
Year			STB			STB			MMSTB			%	MMSTB				%
2010	5		152	160	25	762	799	75	0.01	0.26	0.03	0.2	0.24	0.02	0.26	0.03	0.8
2011	5		163	174	10	817	872	30	0.31	0.34	0.01	28.5	0.55	0.03	0.60	0.04	1.8
2012	5		151	163	10	754	815	29	0.21	0.23	0.01	19.2	0.75	0.02	0.83	0.05	2.5
2013	5		128	151	33	640	753	100	0.21	0.24	0.04	5.7	0.96	0.03	1.07	0.09	3.2
2014	9		154	238	38	1384	2146	265	0.19	0.24	0.10	2.0	1.16	0.05	1.31	0.18	3.9
2015	16		74	129	15	1179	2061	205	0.48	0.75	0.07	6.4	1.63	0.28	2.06	0.26	5.5
2016	16		55	109	30	880	1752	423	0.38	0.67	0.15	2.5	2.02	0.29	2.73	0.41	6.7
2017	16		44	99	7	703	1578	103	0.36	0.71	0.04	9.4	2.37	0.35	3.44	0.45	7.9
2018	16		46	107	29	744	1711	401	0.25	0.54	0.15	1.7	2.61	0.29	3.94	0.60	8.6
2019	16		33	81	32	528	1289	442	0.23	0.53	0.16	1.4	2.82	0.30	4.41	0.76	9.3
2020	18	4	130	295	750	2336	5303	3000	1.00	1.93	1.09	0.9	3.84	0.93	6.36	1.85	12.7
2021	18	4	101	300	750	1823	5407	3000	0.76	1.97	1.09	0.7	4.60	1.21	8.32	2.95	15.3
2022	18	4	84	301	750	1508	5427	3000	0.60	1.98	1.09	0.5	5.20	1.38	10.30	4.04	17.3
2023	18	4	80	310	750	1443	5585	3000	0.54	2.03	1.09	0.5	5.74	1.47	12.30	5.13	19.1
2024	18	4	70	310	750	1258	5585	3000	0.50	2.04	1.09	0.5	6.24	1.55	14.35	6.23	20.8
2025	18	4	64	310	750	1157	5585	3000	0.44	2.04	1.09	0.4	6.68	1.60	16.39	7.32	22.2
2026	18	4	58	310	750	1036	5585	3000	0.40	2.04	1.09	0.4	7.09	1.64	18.43	8.41	23.6
2027	18	4	54	310	750	968	5585	3000	0.36	2.04	1.09	0.3	7.46	1.68	20.48	9.51	24.8
2028	18	4	52	310	750	931	5585	3000	0.34	2.04	1.09	0.3	7.80	1.70	22.52	10.60	26.0
2029	18	4	48	310	750	863	5585	3000	0.32	2.04	1.09	0.3	8.12	1.72	24.57	11.69	27.0
2030	18	4	45	310	750	810	5585	3000	0.30	2.04	1.09	0.3	8.42	1.74	26.61	12.79	28.0
2031	18	4	41	310	750	735	5585	3000	0.28	2.04	1.09	0.3	8.71	1.76	28.65	13.88	29.0
2032	18	4	40	310	750	714	5585	3000	0.27	2.04	1.09	0.2	8.97	1.78	30.70	14.98	29.9
2033	18	4	36	310	750	654	5585	3000	0.25	2.04	1.09	0.2	9.22	1.79	32.75	16.07	30.7
2034	18	4	35	310	750	630	5585	3000	0.24	2.04	1.09	0.2	9.46	1.81	34.79	17.16	31.5
2035	18	4	34	310	750	607	5585	3000	0.23	2.04	1.09	0.2	9.68	1.81	36.83	18.25	32.3

Fig. 16 Oil rate, water cut and recovery factor curve of recommended case

Table 20 The net cash flow for the contractor (50\$/bbl)

Time	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
State net cash flow (US\$ MM)	−27.68	−35.8	−24.6	−45.3	47.66	74.46	74.88	57.29	37.95	34.56	33.59	32.21
Time	2028	2029	2030	2031	2032	2033	2034	2035				
State net cash flow (US\$ MM)	31.09	29.75	28.5	27.6	28.28	27.69	26.97	27.59				
NPV (10%)	132.85 MM\$											
NPV (13%)	88.52 MM\$											
NPV (15%)	66.32 MM\$											
IRR	26.45											
Recovery time (years)	6.15

Fig. 17 IRR sensitivity analysis (50\$/bbl)

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