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Activation of A Dead Well by Injection of Hot Steam

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Abstract

In the context of oil and gas extraction, a dead well refers to a well that has ceased to produce hydrocarbons. This can occur because the reservoir has been depleted, the pressure has dropped too low to allow for extraction, or there are technical issues such as blockages or equipment failure. The main purpose of this paper is to activate the death well called K22 (for confidential reasons) by injecting hot steam into the reservoir to reduce the viscosity of oil and increase the production rate. PVT, reservoir, well, completion and injection data are entered via prosper and Reveal software's in order to analyze the performance of the initial well, to implement the hot steam injection method and to analyze the performance of the well K22 after the injection of hot steam using the nodal analysis method. The results initially obtained show that well K22 does not produce. To solve this problem, the injection of hot steam method provides from the nodal analysis for a liquid production rate of 2200 STB/day and a critical pressure of 2337.78 psi where the production rate of oil is 2187.8 STB/day, the water production rate is 21.1 STB/day and the gas production rate is 0.10894 STB/day for water cut of 0.92 %. The hot steam injection method is appropriate to put in production in well K22 because it reduces the density of the oil which facilitates its flow towards the production well, even though it does not completely solve the problem of water. Therefore, it maximizes the oil production and it allows a profitability of $ 3158366.721 with a return on investment after 3 months and 3 days for 4 years of production. This means that it is possible to recover all the initial cost of exploitation by steam injection within 3 months and 3 days with the production still profitable for up to 4 years.

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1. Introduction

When an oil field is first exploited, hydrocarbons are recovered under the effect of the pressure difference between the reservoir and the downhole [1-3]. This technique, known as primary recovery, recovers 5 to 10% of the oil present in the reservoir. Over time, the pressure drops and becomes insufficient to recover the oil [4-6]. To maintain reservoir pressure, secondary recovery was introduced: water is injected into an injector well to push the oil towards a so-called producer well [7-9]. During production, the volume fraction of water in the recovered fluid continues to increase to the detriment of that of the oil, and digitation phenomena are observed, reducing the performance of this technique [10-12]. With water injection, however, the recovery rate is around 30% of the oil contained in the reservoir [13-15]. Primary and secondary hydrocarbon recovery can only produce a fraction of the oil in place [16-18]. To improve production capacity, oil companies are developing new techniques, grouped under the term tertiary recovery or enhanced oil recovery (EOR), which is a process of extracting oil that cannot otherwise be extracted by the several main techniques that can be thermal, chemical, microbial or gas injection techniques [19-21]. In [22], it is reported that for complicated oil fields, in particular fields with high-viscosity oil, the known traditional methods of development are ineffective. Heat and gas generating systems are then used to treat the bottomhole formation zone on site. The authors of [23] state that depending on the different ways of heat production, thermal oil recovery can be broadly classified into two categories, namely, heat injection methods and in-situ combustion methods. They then showed the effectiveness of these methods, and that oil recovery can be further improved by combining it with other methods. In [24], it is found that in-situ heating exploitation is the most promising method to produce oil from the oil shale, mainly including electrical heating and steam injection heating. They compared the two methods of heating and reported that steam injection heating is superior to electrical heating in output, energy consumption and production cycle.

Well K22 in this study is a new well. It has been brought into production and it has been observed that the oil production rate is progressively decreasing due to the increase in viscosity or density of the oil. Instead of using artificial lift methods to overcome this problem, we are interested in studying an EOR method for optimizing production according to reservoir characteristics. The aim of this paper is to demonstrate that the injection of hot steam, due to its low cost, would be the most favorable and suitable EOR method for increasing the hydrocarbon recovery rate in well K22. This is because hot steam injection makes it possible to reduce the viscosity or density of the oil, increasing its flow rate and consequently the production rate. For this reason, we have the following specific objectives: Evaluate the well's initial performance to determine the cause of the drop in productivity, then implement the hot steam injection method; evaluate the well's performance after implementation of the steam injection method, and make an economic assessment. These objectives will be achieved through nodal analysis and sensitivity analysis using Reveal and Prosper software's, respectively. The present work is structured in three sections. Section 1 presents the introduction. Section 2 presents the data, the software used to achieve the objectives and the various results. Section 3 presents the conclusions.

2. Experimental Procedure

The methodology employed here is the use of Prosper and Reveal softwares. These softwares are used to analyze PVT, reservoir, well, completion and injection data. Then, the well performance analysis, implementation of the hot steam injection method, analysis of well performance after hot steam injection and an economic balance sheet are carried out.

3. Results and Discussion

The data used are presented in Table 1.

Table 1: PVT, reservoir, well K22 and completion data.

PVT and reservoir data	
Tank temperature (°F)	146
Oil density (API)	20
Tank pressure (psi)	2187.948
Gross Porosity (%)	0.195
Water saturation (%)	0.341
GOR solution (Scf/Stb)	50
Gas density (Sp)	0,7
Salinity (ppm)	5000
Water cut (percent)	34,1
Permeability (MD)	2300
Net porosity(%)	0,260
Reservoir thickness (ft)	91
Grainage Area (acrea)	320
Dietz shape factor	31.6
Reservoir radius (ft)	0.51
Skin	3
CP oil (BTU/Ib/F)	0.53
CP water (BTU/Ib/F)	1
CP Gas	0.51
Tank height	92
Top (ft)	5826
Bottom (ft)	5978
Water gravity (sp)	1.02
Well K22 data and completion perforation intervals	
Shaft depth (ft)	6150
Casing size (ft)	6135
Casing diameter (inch)	9.625
Tubing size (ft)	5600
Tubing diameter (inch)	3.826
Tubing and Casing Roughness (inch)	0.0006
Wellhead pressure (ft)	50
Measured well depth (ft)	6135

Figure 1 shows the performance curves for the reservoir and well K22 as a function of reservoir pressure and production flow rate.

Figure 1 : Nodal analysis of well K22 from initial state

Well K22 is not delivering any fluids to the surface, as the lime-green curve (IPR: Inflow performance relation) and the red curve (VLP: Vertical flow performance) do not intersect, as shown in Fig. 1. To overcome this problem, the aim is to use the hot steam injection method to reduce the density of the oil in order to increase the flow rate, and consequently the oil production rate.

1.1. Implementation results from the injection of hot steam

Figure 2 (A, B, and C) shows the 3D models illustrating the injection of hot steam into the reservoir.

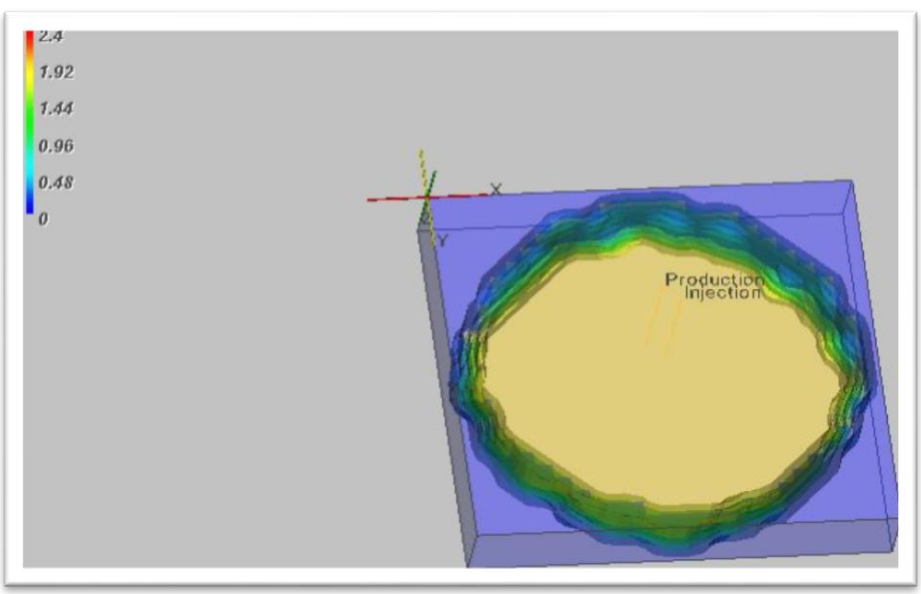

Figure 2: Injection of hot steam into the reservoir for: (A) 5 days.

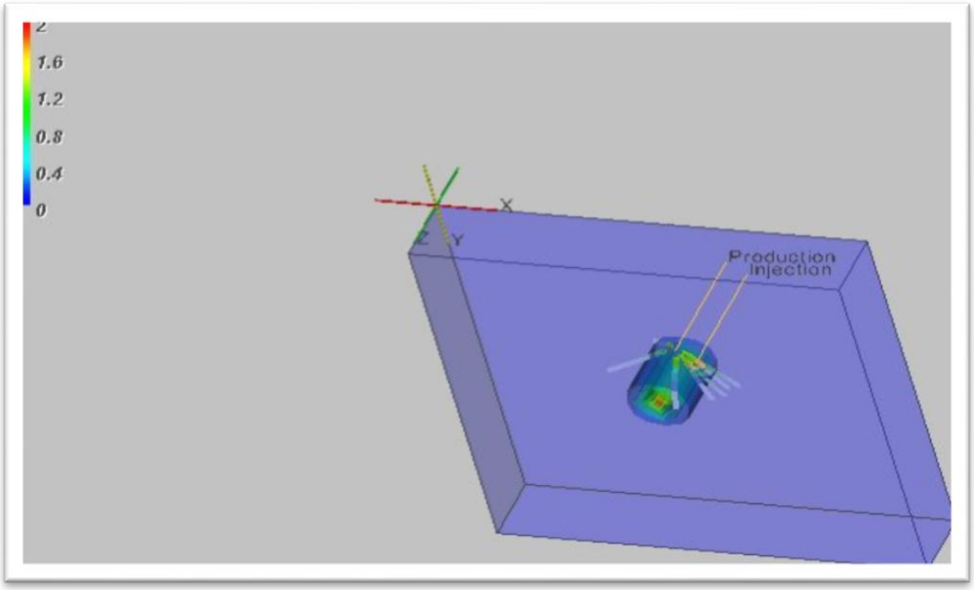

Figure 2: Injection of hot steam into the reservoir for: (B) 370 days.

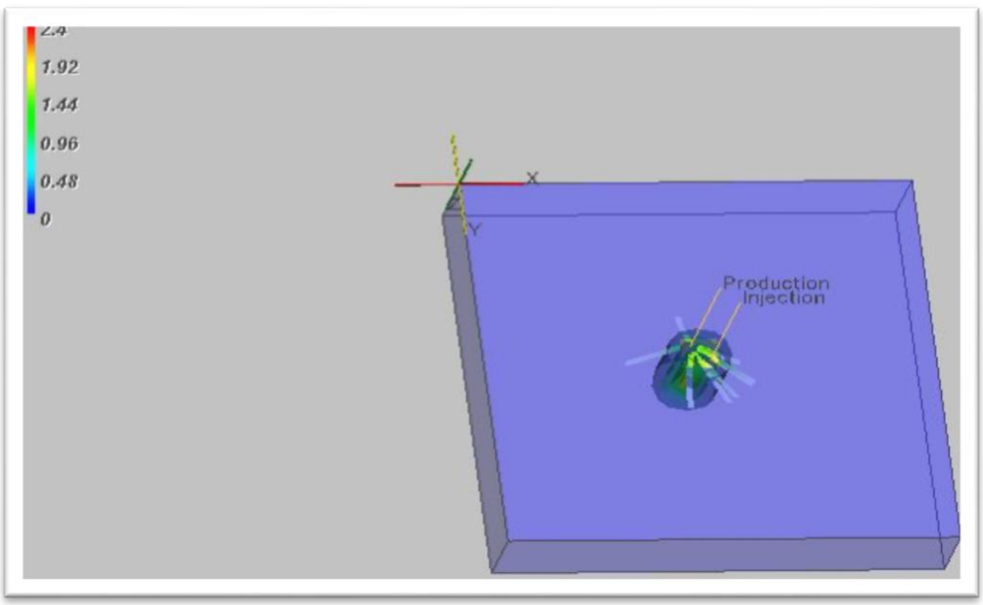

Figure 2: Injection of hot steam into the reservoir for: (C) 506 days.

Figure 2 shows the injection well, drilled parallel to the production well, to facilitate the operation. During this operation, 100 STB/day of steam were injected into the reservoir using an injector well drilled parallel to the producing well for 5 days, then 50 STB/day were also injected over a period of 370 days and 505 days. It is important to note that the injection operation takes place at the same time as production, and the aim is to produce 2100 STB/day of liquid in 370 days and 2200 STB/day of liquid in 505 days. The actual injection is carried out using Reveal software, and the hot steam injection curve from Prosper software is 1imported into the Schedule module of Reveal software for a satisfactory result. The injection of hot steam into the injection well varies parameters such as temperature, water cut and pressure, as shown in Figs 3 and 4. Figure 3 (A and B) shows the temperature variations from the moment hot steam is injected to the moment of production.

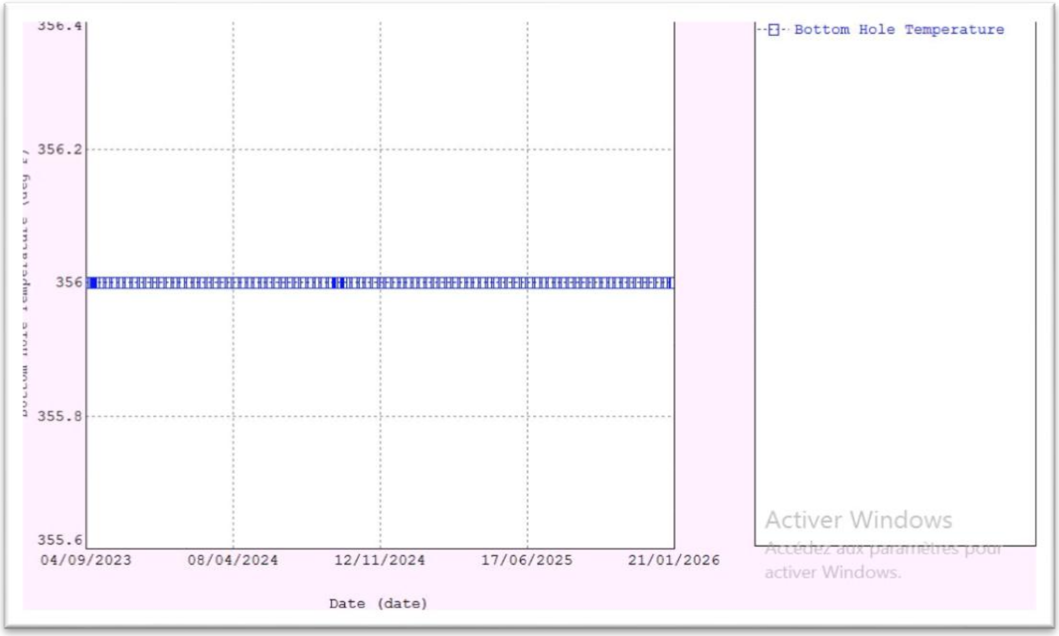

Figure 3: Temperature variations during: (A) Injection

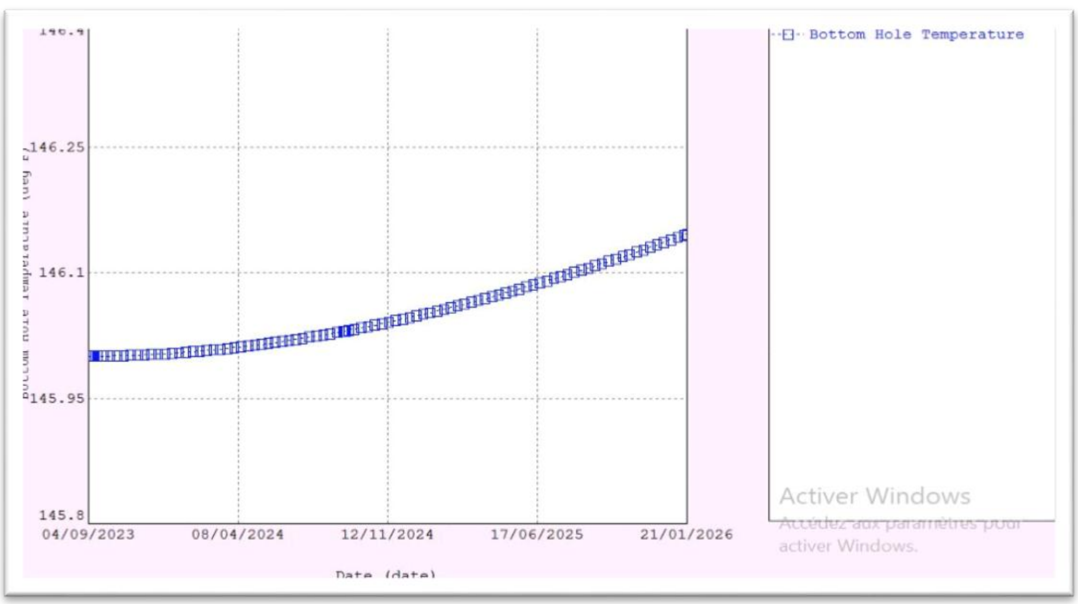

Figure 3: Temperature variations during: (B) Production.

From Fig. 3 (A), it is imperative to note that, during the injection period which runs from September 4, 2023 to January 21, 2026, the temperature remains constant at a considerable 356°F. This contrasts with the production period, when the temperature rises from 146.001°F to 146.144°F (see Fig. 3 (B)). As shown in Fig. 3, the injection of hot steam at a temperature of 356°F raises the temperature in well K22 to 146.144°F. Variations in K22 well drainage and bottomhole pressures from the time of hot steam injection to the time of production are shown in Fig. 4 (A and B).

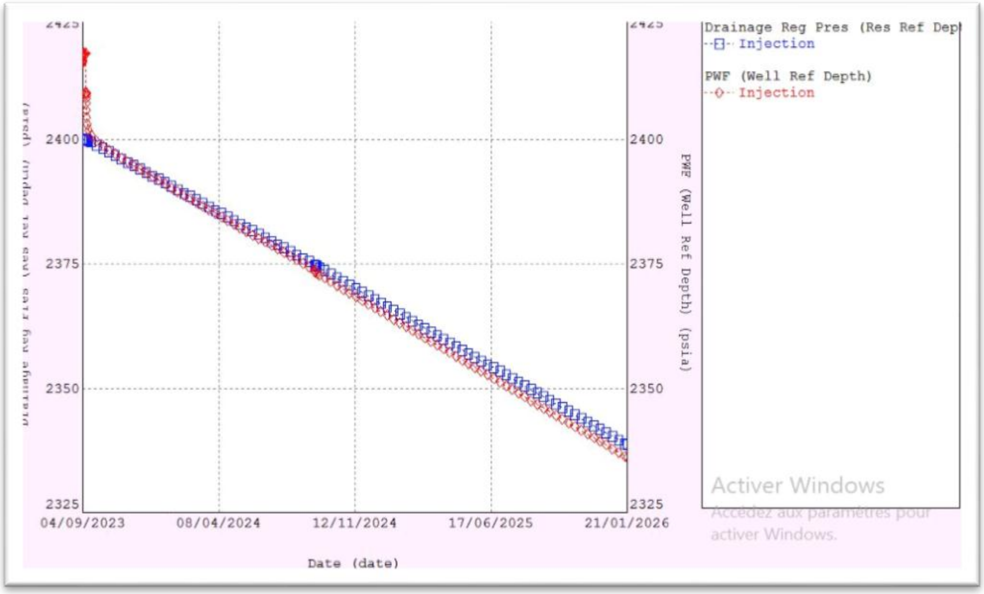

Figure 4: Variations in drainage pressure and bottomhole pressure in well K22 during: (A) Injection.

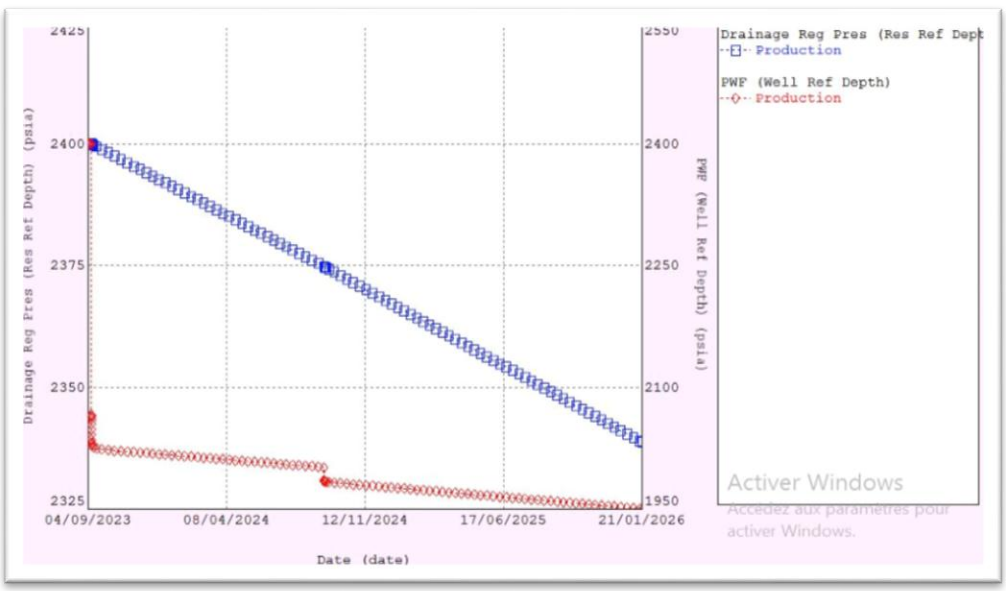

Figure 4: Variations in drainage pressure and bottomhole pressure in well K22 during: (B) Production.

Figure 4 (a) shows a considerable drop in pressure, from 2418.01 psia to 2336.07 psia for bottomhole pressure, and from 2400 psia to 2338.26 psia for drainage pressure. Pressures also fall during the production period, from 2400 psia to 2031.75 psia for drainage pressure, while bottomhole pressure varies in several levels, as shown in Figure 4 (b). From September 4, 2023 to September 10, 2023, it drops to 2031.75 psia (5-day production period), then from September 10, 2023 to September 9, 2024 it drops to 1983.68 psia (one-year production period) and reaches a pressure of 1950 psia at the end of production on January 21, 2026. Final confirmation of the effectiveness of the hot steam injection method will be provided by a nodal analysis. Figure 5 shows the well function point after hot steam injection.

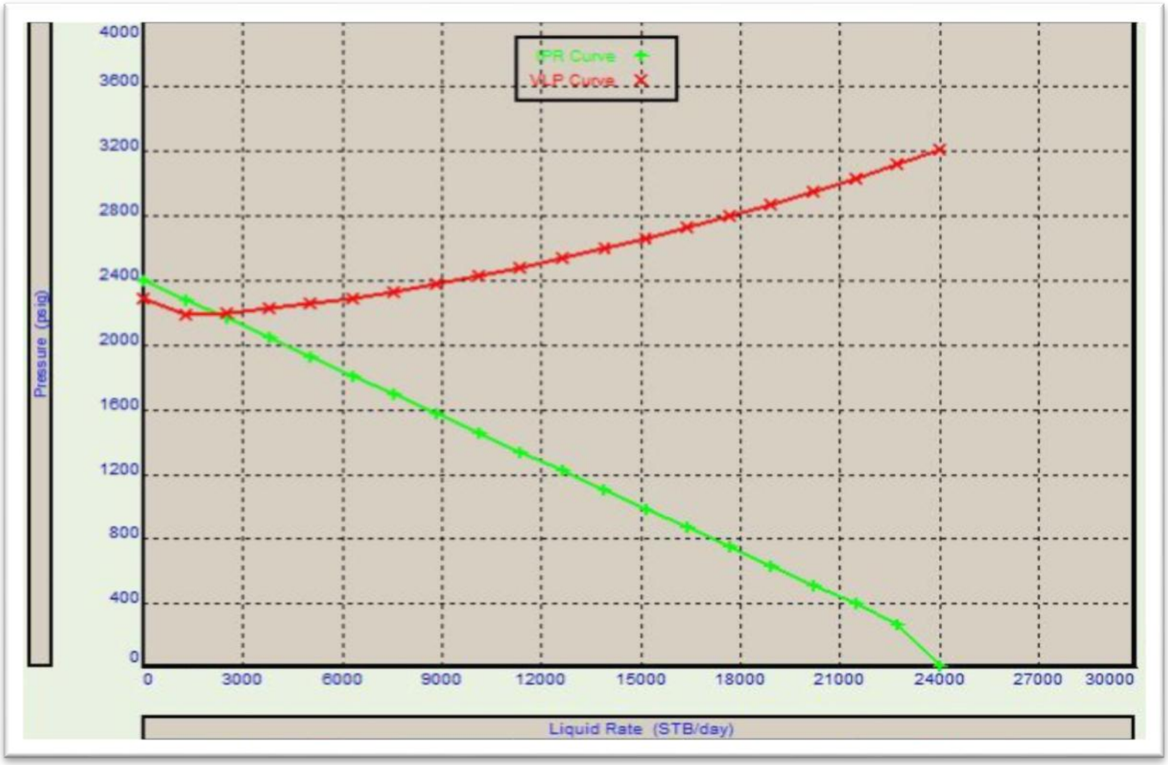

Figure 5: IPR and VLP curves after hot steam injection.

Figure 5 shows the intersection of the IPR curve in lime green and VLP in red within the operation point, giving a liquid production rate of 2200 STB/d with a bottom pressure of 2337.78 psig. The liquid production rate of 2200 STB/day corresponds to 2178.8 STB/day of oil production, 21.1 STB/day of water and 0.11 STB/day of gas with a water cut of 0.91%. This water cut is less that 1% and so is very good for oil production. High water cut ranges from 40% to 80%; as the case may be. Table 2 shows cumulative oil production from the K22 well after hot steam injection.

Table 2: Cumulative oil production from well K22 after hot steam injection.

Injection period	Cumulative oil production (STB)
04/09/2023	10250
09/09/2023	32250
08/09/2024	771500

According to the results in Table 2, cumulative oil production shows a significant yield from well K22 after hot steam injection.

1.2. Economic balance sheet

The period during which the economic balance sheet is made is determined by Fig. 6.

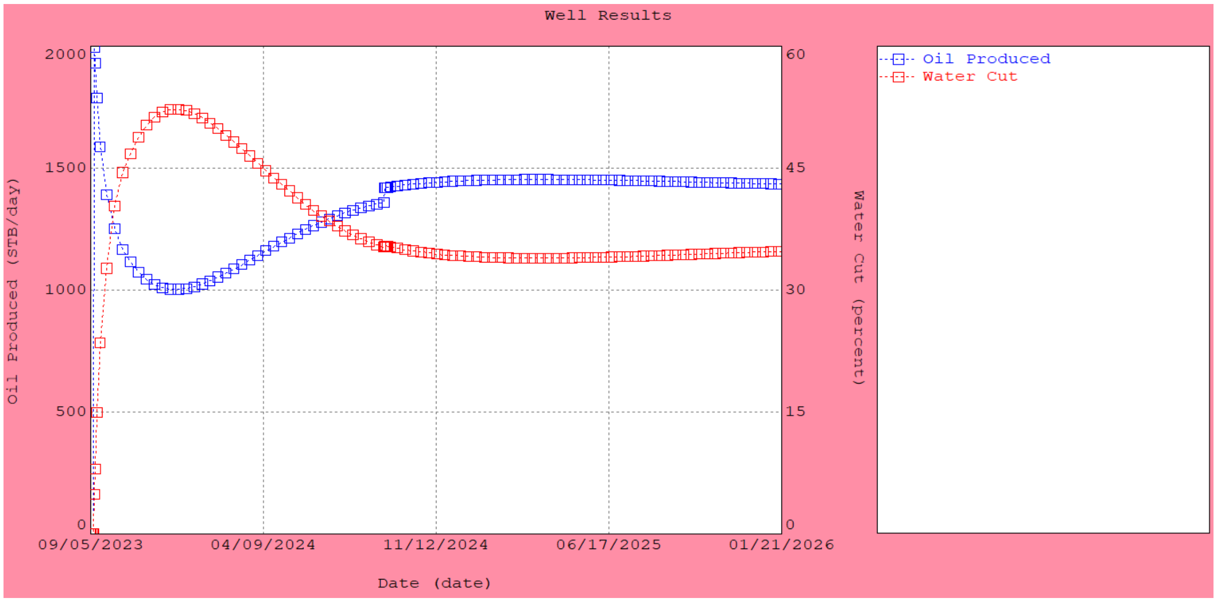

Figure 6: Production profile of well K22 after injection of hot steam as a function of time.

Figure 6 shows that, initially, we start with zero flow due to the non-eruptivity of the K22 well. Steam injection through the injection well results in a decrease in the density (56.92 lb/ft3 to 53.97 lb/ft3) and viscosity (31.94 cp to 7.31 cp) of the oil. This results in lower pressure losses due to potential energy, as well as lower VLP. The decrease in VLP allows the K22 well to start producing at a rate of 2100 STB/day for approximately 1 year 7 days. Finally, the production rate of 2200 STB/day remains constant for approximately 2 years, 5 months and 5 days, for a production rate of 2178.8 STB/day. Thus, the steam injection operation is implemented over a period of 3 years, 5 months and 12 days. Before making the final decision on steam injection implementation, a thorough economic analysis must be carried out. The profitability of a project must be the criterion for the final decision. The net present value (NPV) will give the value of a project over its entire lifetime, taking into account investment costs and revenues. Table 3 shows the start-to-finish costs of hot steam injection (including procurement, construction and administration costs), operational costs during installation, maintenance rates and total expenditure.

Table 3: Capex and Opex.

Capex	
Surface equipment	100000 $
Equipment rental	60000 $
Tax	1465169,03 $
Opex	
Water injection	10000 $
Operating costs	20000$
Maintenance costs	70000 $
Price per barrel of oil	50 $

The results for revenue, total expenditure (Capex and Opex), profit and return on investment were calculated in Excel, and the answers are presented in Table 4.

Table 4: Results on the economic balance of the operation.

Total revenue	Total tax	Total expenses	Cash-flow	Net cash-flow	NPV	RI
96367793.5 $	14655169.03 $	20987456 $	75380337.5 $	49154435.18 $	3158366.721 $	0.26

Table 4 shows that the return on investment is after 3 months and 10 days, i.e. the period during which the company will recover all its expenses

4. Conclusions

Ultimately, the aim of this paper was to use an injector well to inject hot steam into the reservoir to reduce the density of the oil and facilitate its movement into the producing well, with a view to increasing the oil recovery rate in well k22. This operation was put into action using Prosper and Reveal software's, by analyzing PVT, reservoir, well, completion and injection data. These data were highlighted through the methods of initial well performance analysis, implementation of the hot steam injection method, analysis of well performance after hot steam injection and an economic balance sheet. According to the results presented chronologically, the performance curve of the initial well K22 shows that this well does not produce. After injection of hot steam, reservoir temperature rises. Likewise, the water cut dropped to 0.91% due to water vaporization, which has an impact on oil mobility in well K22. In the reservoir, pressure dropped as a result of pressure losses at the bottom of well K22 due to potential energy. In addition, the liquid production rate increased remarkably, to 2178.8 STB/day, due to the rise in temperature and the reduction in head losses, which lowered hydrostatic pressure. The oil production flow rate increased considerably compared with the water production flow rate of 21.1 STB/day and 0.10894 STB/day for gas production. The validity of the project has been established through the positive net present value of $3158366.721, with a return on investment in 3 months and 3 days for a production period of 4 years.

Conflict of Interest: The authors declare that they have no conflict of interest.

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