# Infill Drilling Optimization for Enhanced Oil Recovery by Waterflooding: A Simulation Study

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**Abstract:** There are many mature oil fields in the North Sea. One of them is the Clair Oil Field, located on the United Kingdom Continental Shelf (UKCS) in Scotland. This oil field is unique because of the results of failure studies of several fluid injections, constituting secondary and tertiary oil recovery techniques, on increasing oil production. Only waterflooding has shown a promising future. In this paper, three-dimensional (3D) numerical simulations investigate the influence of infill drilling optimization by waterflooding in the Clair Oil Field so as to maximize net present value (NPV). An important goal of this study of reservoir management was to determine optimal well locations and optimal operational parameters (production constraints) that maximize cumulative oil production. Theoretical ideas and mathematical models with field data performance demonstrated the factors that can be considered in infill drilling so as to increase oil reserves. Most of the factors were related to reservoir heterogeneities and were important quantitatively for fluid injection and production. The results revealed that the four infill wells added in this study led to an increase in the field's total cumulative oil production from $7.91 \times 10^6$ to $9.39 \times 10^6$ $m^3$. The NPV after infill drilling optimization by waterflooding increased by 54.4% over the base case. The oil recovery factor rose from 17.2% to 20.2%, while the gas oil ratio (GOR) fell from 1,000 to 840 SCF/STB. After combining infill drilling with waterflooding, the horizontal infill producers outperformed vertical infill producers by 5.5%. The field water cut was reduced from 95% to 88%. In addition, an analysis of cumulative production between parent and child wells was made. It was found that child wells produce less cumulative oil production than do parent wells. This paper reveals the greater success of a combination of infill drilling with waterflooding in enhancing oil production compared to other findings where the influence of infill drilling and waterflooding were analyzed separately or compared. It can be concluded that the Clair Oil Field has great potential to increase oil production by combining infill drilling with waterflooding, after other improved oil recovery techniques fail. **DOI: 10.1061/(ASCE)EY.1943-7897.0000860.** 

**Author keywords:** Infill drilling; Net present value (NPV); Waterflooding; Cumulative oil production; Reservoir management.

## Introduction

Global energy demand is increasing faster, driven by industrial evolution in developing countries and emerging high living standards around the world. Energy demand growth is expected to exceed 50% of current consumption between 2018 and 2050. Most energy demand will be from countries that are not members of the Organization for Economic Cooperation and Development (OECD). The fast and strong economic growth in Asia-Pacific countries will make them the world's most energy-consuming region (EIA 2019). Fig. 1 shows the energy history and projection by region in quadrillion British thermal units (BTU). This energy projection demand has led both to the search for new sources of energy, and to research on how to exploit the remaining oil in matured reservoirs. Enhanced oil recovery (EOR) represents 2% of oil global production, and did so even during the higher oil price era between 2010 and 2014 (Fanchi 2010; Manzoor and Kohan Hooshnejad 2018). In 2013, it was estimated that 300 billion bbls of oil would be produced in the mid-2020s by available EOR technologies. Unfortunately, only a small percentage has been produced, as a result of the increase in shale production in the United States, Brazil, and Canada, leaving little room for EOR growth. It is expected that, between 2025 and 2040, oil production by EOR techniques will grow from 2.7 million bbls/d to more than 4.5 million bbls/d and will account for 4% of total global oil production (Capuano 2018; BP Energy Economics 2018; Iqbal and Satter 2016; Newell and Raimi 2020; Pei et al. 2021). Currently, most operating companies are focusing on increasing their estimated recovery factors and reaching higher economic oil production rates. The reason for this is that discovering new oil fields has become difficult, because most of the promising hydrocarbon basins have already been explored (He et al. 2021; Mao et al. 2021; Raslan and Sultan 2012), and unexplored areas such as the Arctic and Antarctic regions are environmentally sensitive and remote areas. Unconventional reservoirs are another source of hydrocarbons, but oil price fluctuations associated with technological challenges such as hydraulic fracturing and horizontal drilling make producing these resources uneconomical (Huang et al. 2016). During oil production, there is a point at which where the production cost of an added barrel of oil becomes higher than the market price of that barrel (Lake et al. 1990; Pei et al. 2020). Wells are often-in for economic reasons with more than 70% of oil initially in place (OIIP) left in the reservoir (Alusta et al. 2012; Dheyauldeen et al. 2021). EOR techniques have become an

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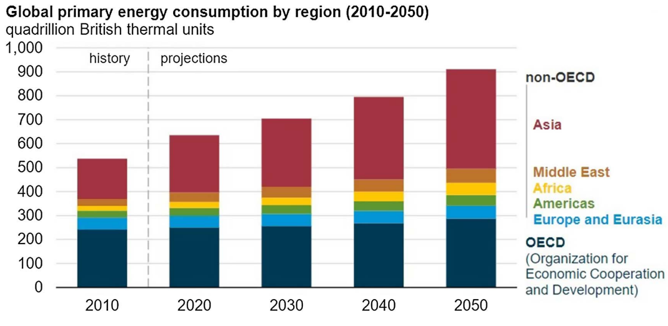


**Fig. 1.** Global primary energy consumption by region in quadrillion BTU (2010–2050). (Reproduced from EIA 2019.)

important area of research, because oil will be an even-more limited source of energy for future generations (Jin 2017). Thus, infill drilling optimization, that involves additional of new wells to the oil/gas production field, has become more important.

Several researchers have done modeling and simulations on the potential of infill drilling to increase oil recovery from reservoirs in injection operation oil fields and non-injection operation oil fields. Recently, a deep learning convolution neural network (CNN) was applied to optimize the location of vertical infill wells to overcome heterogeneity problems. The inputs of the multimodal were both static and dynamic parameters. The CNN results matched the reservoir simulation outputs at a minimum number of simulations; agave a small relative error of less than 10%, compared to full physics simulations; and outperformed other simulation techniques, such as feedforward neural networks and backward neural networks. Furthermore, it was discovered that partial machine learning methods, such as CNN, can replace reservoir simulators in field development for optimizing well locations (Chu et al. 2020).

Chen et al. (2022) applied infill drilling as an enhanced recovery technique so as to increase gas production in the Fuling shale formation in the Sichuan Basin, China. They developed a workflow that can be used for infill drilling optimization even without considering the previous production of the existing wells. Furthermore, they found that there was a good relationship between field observations and the predicted model. Popp (2020) optimized well locations by adding more wells, so as to increase the estimated ultimate recovery (EUR) in the Montney gas field formation, western Canada, by 3–5 years. Popp also applied statistical analysis to optimize well locations in non-depleted areas. He found that the infill drilling increased the estimated ultimate recovery by 5% within a year, compared to the initial gas production. Cheng et al. (2009) designed an efficient and systematic method for infill drilling optimization that can be applied to tight gas reservoirs. After application of this technique to the gas field, the field's cumulative gas production increased from $6.9 \times 10^7$ to $82 \times 10^7$ MMSCF within three years of production. Salmachi et al. (2013) optimized well locations so as to maximize the net present value (NPV) of the Tiffany coal bed field in the San Juan Basin in northwestern New Mexico by using a commercial reservoir simulator (Eclipse 100) and MATLAB with a genetic algorithm as an optimizer. They used NPV as an objective function. The infill wells added, increased the NPV by 5.7% and 5% for low and high cost of water treatment, respectively. The greatest number of infill wells were located in unexplored (virgin) areas of the reservoir, which had higher pressure than the non-virgin zones. Also, they found that if water treatment costs are high, the infill wells should be located in the areas between virgin and non-virgin zones, whereas if water treatment costs are low, the infill wells should be located in non-virgin zones.

Guo et al. (2019b) used reservoir geomechanics to investigate the effects of injection parent wells on interference of fracturing near wells. They found that nearby injection parent wells led to fracture extensions, which helped to improve the well completion quality of infill wells. Furthermore, they found that the successive volume of injected fluid is a vital factor for well-to-well interference and improving the completion quality of infill wells. Also, Guo et al. (2018) analyzed the effects on parent wells of induced stress by infill wells in the Eagle shale gas field. They found that small bottom hole pressure, differential stress, and the fracture geometry of parent-producing wells affect the infill well's production performance by inducing greater stress. Guo et al. (2019a) modelled the effects of induced in-situ stresses on infill wells from subsequent asymmetric evolution of parent-well-depletion child wells. They found that uneven changes in stresses affects the infill well's production performance. Child wells were asymmetric affected by their locations, induced stress contrast by parent wells, and production of parent wells.

Wu et al. (1989) analyzed the ultimate oil recovery increment in the oil reservoirs located in the northern parts of the central, midland, and southern basins of the Matador Arch. They employed decline curve analysis (DCA) to estimate ultimate oil recovery from infill drilling with waterflooding, and found that infill drilling accelerated the oil production rate and increased ultimate oil recovery through waterflooding. All three types of DCA were applied to estimate ultimate oil recovery, and hyperbolic and exponential decline curves were found to give the most positive responses. The economical production rate per well was estimated to be 3 times stock tank barrel (STB)/d. French et al. (1991) used statistical and fuzzy logic approaches to develop models for infill drilling effects on waterflooding in the West Texas San Andres and Clearfork carbonate reservoirs. At first, the statistical approach experienced many failures due to uncertainty and poor selection of input parameters from the data base. After several attempts using different variables, the models showed improvement on oil production due to infill drilling and waterflooding effects. Later, they applied a fuzzy logic system to observe how infill drilling with waterflooding can increase oil recovery, and found that the fuzzy logic model outperformed the statistical approach. They reported that, when well fractional spacing was reduced from 0.23 to 0.25, the ultimate oil recovery increased by 5%–7% of the original oil in place (OOIP).

Further in the western part of the Canadian sedimentary basin, Singhal et al. (2005) found that infill drilling with waterflooding was economical and successful under favorable conditions. They concluded that: (1) Recovery of heavy oil showed greater success than medium and light oil during flooding, (2) horizontal wells outperformed vertical wells, (3) infill well optimization was successful in areas where the oil recovery factor for waterflood is large and water cut is low, and (4) the infill well production by water flooding shows a lognormal distribution of cumulative oil production. In this basin, the most important factors that led to successful infill well waterflooding were: (1) A remaining reserves index of 10 years or more, (2) water cut less than 75%, (3) heterogeneity presence, so that unexplored reserves could be produced, (4) porosity greater than 10%, and (5) thickness greater than 6 m.

Sayyafzadeh et al. (2010) applied the streamline simulation technique to investigate how to increase ultimate oil recovery (UOR) by infill drilling with waterflooding. They analyzed separately the effects of infill drilling and converting producer wells to injector wells, and vice versa. Their results revealed that the incremental effect of infill drilling on UOR was 3,336,679 STB in the region of lower streamline density, and 1,729,815 STB in the region of high streamline density. They concluded that the streamline technique increased UOR by 70%. Without both infill drilling and well switching, UOR was 74,500,000 STB and after both infill drilling and well switching, UOR was 124,000,000 STB.

Infill drilling optimization with waterflooding has also been applied successfully in the low permeability WY Reservoir in the Ordos Basin in China (Yu et al. 2018). Infill wells were located in the regions of high-water breakthrough, which were converted to injector wells during simulations. After field applications, the infill drilling optimization increased the production by 13% and reduced water cut by 6%. Furthermore, the UOR was 5% greater than the origin oil in place (OOIP). Infill well placement optimization by waterflooding in a heterogeneous reservoir was simulated by using an upscaled wavelet transform, applying a five-spot waterflooding pattern. Yu et al. observed that upscaling wavelet transform gives the optimal well locations of both injectors and producers by maximizing ultimate oil recovery between 1.95% and 3.5%, and proposed that the method be applied to any water flooding pattern. The method reduced simulation runs between 75.5% and 93.4%. Yu et al. established processes to follow when upscaling heterogeneous reservoir models so as to determine the optimal well placements (Malallah et al. 2021).

Infill drilling placement was applied in the Grayburg field, West Texas. For the case Infill Water Flooding B, infill wells reduced the water cut from 85% to 50%. Ultimate oil recovery increased from 4,565,800 to 7,008,200 bbl. (i.e., around 18.6% to 28.5%), and the ultimate oil recovery increased by 5.4% over the original oil in place (Driscoll 1974). In an Iranian oil field, Dailami et al. (2017) optimized infill well placement of horizontal and vertical wells so as to maximize the oil recovery factor. Streamline simulation was applied for the investigation. They found that infill well optimization of both horizontal and vertical wells increased oil recovery factors from 20.02% to 32.75%. Based on horizontal and vertical well recovery factors, horizontal wells outperformed vertical wells. Wang et al. (2007) optimized the placement of injection wells using a new algorithm. Their technique was to place an injection well in each grid block that did not have a production well. The objective function was NPV. The NPV was maximized by changing the well injection rates, reducing the number of injections wells to one well and increasing the number of iterations; i.e., 220 iterations gave an NPV of $\$1.20\times10^8$, versus $\$3\times10^7$ when the number of iterations was zero. When the objective function was zero in a particular well, that well and its associated costs were eliminated from the objective function.

In addition, a machine learning (ML) technique, xGBoost, and an experimental-based method, central composite design (CCD), were examined for well placement optimization problems. Their efficiencies in well location optimization were different in various reservoir scenarios. Their efficiencies were measured by the NPV objective function. xGBoost outperformed CCD on well placement optimization prediction and on accuracy, with an R-squared of 0.998 for xGBoost and 0.934 for CCD (Mousavi et al. 2020). Also, hybrid genetic algorithms (GA) combined with polytope search techniques were applied for field development to optimize well location. Vertical and horizontal well placement distributions were optimized in the oil field so as to maximize NPV. By combining GA with polytope search, they minimized simulation time and geologic uncertainties and maximized NPV, and the project profit increased by 6% (Bittencourt and Horne 1997).

Sarma and Chen (2008) developed gradient-based optimization algorithms and adjoint models for optimizing well locations. The algorithm efficiency and feasibility were verified in well placement optimization waterflooding case studies. The algorithm was found to better identify the optimal well locations compared to non-gradient algorithms like the genetic algorithm. The sweep efficiency improved and the NPV increased by 8% over the base case. Alghareeb et al. (2014) applied a modified cuckoo search (MCS) for well placement optimization and injection rate monitoring. The technique has filters inside, which help to deal with nonlinear constraints. The MCS outperformed the GA in the rate of convergence, i.e., the MCS converged faster than did the GA (250 simulations versus 850 simulations). The MCS also had a greater NPV, and increased oil recovery to 79% (compared to GA's 75%), from a base case of 60%.

Jesmani et al. (2015) applied a particle swarm optimization (PSO) algorithm was optimizing well locations in field development. Eight vertical wells were optimized in an irregular well pattern based on maximizing oil recovery and NPV. PSO increased the NPV by 16%. Centilmen et al. (1999) used a reservoir simulator combined with a trained artificial neural network (ANN). The reservoir simulator provided the training data to ANN; then, ANN was used to predict the optimal well location. They found that the neuro-simulation approach was faster than conventional methods, because it reduced the number of simulations. Cumulative gas production increased from 85 to 140 MMSCF/d without and with infill wells, respectively. Zandvliet et al. (2008) applied the adjoint gradient method in optimizing well locations so as to maximize NPV. They found that the method improved net present value (NPV) of the reservoir field by 6% (in Example 2) and 4% (in Example 1). Other research on infill drilling optimization is provided in Table 1.

The main objective of this paper was to model and simulate areas for new wells in the waterflooded Clair Oil Field, in order to obtain the optimal operational parameters to maximize the NPV for the planned second phase of field development. A 3D reservoir model was built and simulated based on field data, and optimal operational parameters that maximize oil production and lengthen the life span of injection and producer wells were found by a commercial reservoir simulator. Other mathematical models were used for modeling and simulation to assess reservoir characteristics. The simulator proved to be quite successful at optimizing well locations for field development problems. The combination of infill drilling and waterflooding influence on NPV was analyzed differently from most other research, in which infill drilling and waterflooding are analyzed separately. The findings of this paper can serve as a reference and base for all oil fields where other enhanced oil recovery techniques have been unsuccessful, like the Clair Ridge Oil field having the same nature, geological location, and characteristics.

## Methodology

### *Clair Oil Field*

Clair Oil Field, located in the North Sea, is one of the largest UKCS oil fields. It was discovered in 1977 and covers an area of 220 $km^2$. It is located 229 km from the Scottish mainland and 75 km from the western part of the Shetland Islands. Its recoverable reserves are around 1.3 billion cubic meters. Initially, 15 appraisal wells were drilled, and later in 1966, flow tests were conducted. Due to the field's complexity, three more appraisal wells were added during its development, which was divided into two phases.

Clair's first phase of development began in 2004, with the extraction of oil from the reservoir's horst, core, and graben areas by waterflooding, as shown in Fig. 2. Production started in 2005 and was exported to the fixed platform through a pipeline. Through the end of 2014 the oil production was over 16 billion $m^3$. This success paved the way for the Phase Two development. Clair Phase Two development involved the exploitation of hydrocarbons from the Clair Ridge of the reservoir, located 5.6 km from Clair Phase One. The second phase involved the application of technological methods of enhancing oil production by using different enhanced oil recovery techniques supported by different subsea equipment,

**Table 1.** Summary of infill drilling operations on improving oil recovery

| No. | Case study/operational type | Formation type | Wells added | Comments | References |
|---|---|---|---|---|---|
| 1 | Johnson J.L "AB" unit offshore oil field West Texas | Low permeability carbonate reservoir | 3 producer wells | Cumulative recovery of 9% OOIP was increased | Yadavalli et al. (1991) |
| 2 | Ohio offshore oil field | Low permeability sandstone | 35 wells | Oil recovery factor increased from 11% to 13% | Wozinak et al. (1997) |
| 3 | Tapis offshore oil field in South China | Extremely heterogeneous sandstone | 50 wells | 30% of OOIP increased | Abdullah and Olsen (1999) |
| 4 | Clearfork and San Andres offshore West Texas | Carbonate | 10 acres well spacing (107 wells) | 6.9% of OOIP increased | French et al. (1991) and Reviere and Wu (1986) |
| 5 | North Kadi onshore oil field | Sandstone | 32 infill wells | 26% of oil production increased | Ghosh et al. (2004) |
| 6 | Bombay Western offshore oil field | Heterogeneous carbonate reservoir | 48 infill wells | Oil field production increased from between 500–530 bopd/well | Tewari et al. (2000) |
| 7 | Barrow Island offshore oil field | Extremely complex sandstone | 182 infill wells | Field oil production notably increased | Allard et al. (1999) |
| 8 | Malaysia St Joseph offshore | Sandstone | 3 production wells | 3,200 bbl/d of oil were added | Offshore (2019) |
| 9 | Malaysia North Sabah offshore | Sandstone | 4 production wells | Field oil production increased by 2,200 barrels per day | Offshore (2020) |
| 10 | Western onshore Desert of Egypt oil field: Case studies | Low-permeability and heterogeneous reservoirs sandstone with laminated shale barriers | 101 infill production wells | Field oil production increased by 11.14 MMSTB | Awad et al. (2015) |
| 12 | Nine onshore oil fields in Texas, Oklahoma, and Illinois | Carbonate and sandstone reservoirs | 870 infill wells | Field oil recovery increased from 56% to 100% in their wellbore production | Barber et al. (1983) |
| 13 | Sacatosa offshore (San Miguel-1 sand) field | Sandstone | 193 infill wells | 1,700,000 bbl. of oil increased | Davis and Shepler (1969) |
| 14. | Wassana offshore oil field Thailand | Sandstone | 2 infill horizontal wells | Oil production increased from 4,377 b/d to 5,875 b/d | Offshore (2018) |
| 15 | Espoir field off Côte d'Ivoire | Sandstone | 2 infill production wells | Net additional oil production 5,100 bbl/d | Offshore (2015) |

which will extend the life of the field into the 2050s. The main operator of the field is BP, with a 28.6% interest. The other partners were Shell (27.97%), ConocoPhillips (24%), Harbour (7.5%), and Chevron (19.43%). In 2018, Conoco Phillips sold its shares to BP and Harbour, now BP owns 45.1% and Harbour owns 7.5%. In March 2021, Harbour reported the failure of expected oil production from nine drilled wells, because of poor well locations and early water breakthrough. BP, as the main operator, is expecting to continue searching for reliable techniques to maximize oil production.

## Clair Oil Field Reservoir Characteristics

The Clair formation is a part of the supergroup of old red sandstone, and is divided into two parts: the upper Clair group (early carboniferous) and the lower Clair group (middle to late Devonian). The Clair Oil Field sediments were deposited by fluvial flows, especially river streams carrying the materials from southwest to northeast. The field is bounded by fractures and faults, which give the reservoir heterogeneity. The best oil reservoir in the field is the lower Clair group, which was exploited in Phase One development and is a target for Phase Two development. In Phase One, production was low (approximately a 17% recovery factor), due to the heterogeneity of and extensive fractures in the reservoir. Production revealed that there is still oil remaining in the reservoir matrix, as well as some in virgin zones. In the Phase Two development, some enhanced oil recovery (EOR) techniques, such as polymer flooding, carbon dioxide flooding, and gas flooding, have not been successful in improving oil recovery. So, only water-flooding has remained as a meaningful recovery technique.

## Simulation Method

CMG-IMEX (2020 version) is a black conventional oil reservoir simulator used for history matching and prediction of primary, secondary, and tertiary oil or improved oil recovery processes. CMG-IMEX 2020 was employed in building the model in this study. IMEX models the hydrocarbon production and management of sandstone and carbonate reservoirs. Multiple pressure, volume and temperature (PVT), rock types, and equilibrium regions were modelled by IMEX, giving more flexibility in relative permeability selection. After building the model, CMOST-AI (2020 version) was used for infill drilling optimization purposes. CMOST-AI 2020 now has artificial intelligence (AI) and ML reservoir modelling and simulator capabilities. It is very capable at combining machine learning, improved statistical analysis, and non-biased data for identifying the best solution and easy interpretation. Fig. 3 shows the steps followed in this paper for infill drilling optimization. The general black oil governing equations for CMG IMEX multiphase flow are given as (Azin and Izadpanahi 2022)

Oil:

$$\Delta T^x_{of}(\Delta p^{n+1}_{of} - \gamma^x_{of}\Delta D) + T^x_{omf}(p^{n+1}_{omJ} - p^{n+1}_{of}) + q^{n+1}_o - \frac{V_b}{\Delta t}\left[\left(\frac{\phi S_O}{B_O}\right)^{n+1}_f - \left(\frac{\phi S_O}{B_O}\right)^{n}_f\right] = 0 \quad (1)$$

Water:

$$\Delta T^x_{wf}(\Delta p^{n+1}_{wf} - \gamma^x_{wf}\Delta D) + T^x_{wmf}(p^{n+1}_{wmJ} - p^{n+1}_{wf}) + q^{n+1}_w - \frac{V_b}{\Delta t}\left[\left(\frac{\phi S_w}{B_w}\right)^{n+1}_f - \left(\frac{\phi S_w}{B_w}\right)^{n}_f\right] = 0 \quad (2)$$

where T = transmissibility; p = pressure; q = flow rate; S = saturation; B = formation volume factor; mf = convection mass transfer; and V = the volume of the respective fluids.

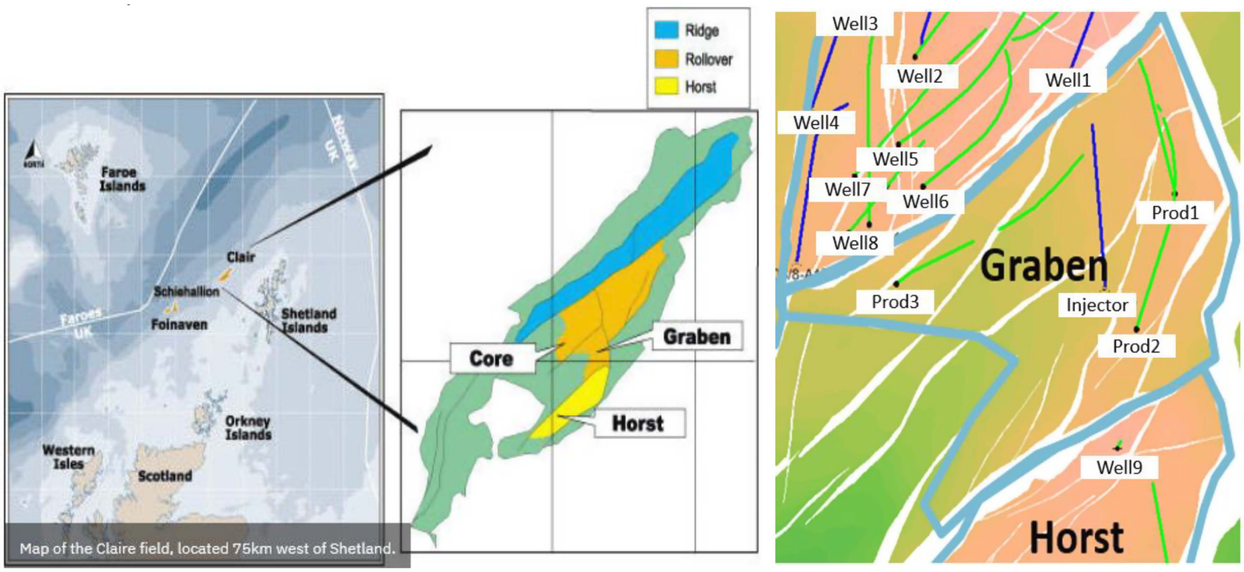


**Fig. 2.** Clair oil field in UKCS modified from. (Used with permission of Society of Petroleum Engineers, from *International Petroleum Technology Conference*, "A multidisciplinary approach to production optimization through hydraulic fracturing stimulation and geomechanical modelling in Clair field," L. Dumitrache, A. Roy, A. Bird, B. Goktas, C. Sorgi, R. Stanley, V. De Gennaro, E. Eswein, and J. Abbott, © 2022; permission conveyed through Copyright Clearance Center, Inc.)

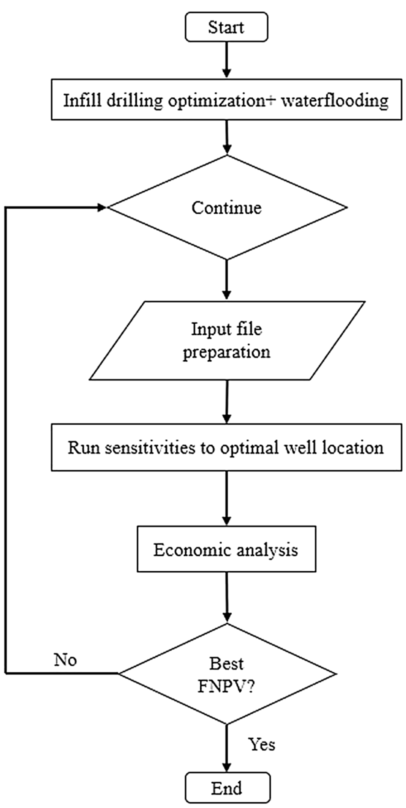


**Fig. 3.** Flowchart used for infill drilling optimization.

And for matrix sub block k:

$$T^x_{\alpha m_{k-1/2}}(p^{n+1}_{\alpha m_{k-1}} - p^{n+1}_{\alpha m_k}) + T^x_{\alpha m_{k+1/2}}(p^{n+1}_{\alpha m_{k+1}} - p^{n+1}_{\alpha m_k}) - \frac{V_{b_x}}{\Delta t}\left[\left(\frac{\phi S_\alpha}{B_\alpha}\right)^{n+1}_m - \left(\frac{\phi S_\alpha}{B_\alpha}\right)^{n}_m\right] = 0 \quad (3)$$

where $\alpha$ can be oil or water.

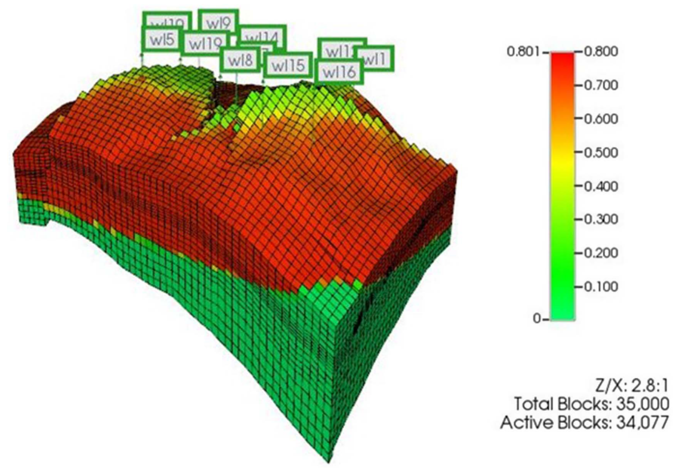


**Fig. 4.** 3D reservoir model of the Clair Oil Field, showing oil saturation before infill drilling optimization.

These equations arise from three sources: material balance equations, phases equilibrium, and constraint equations.

### *Description and Setup of the Model*

A single porosity, two-phase water-oil and 3D reservoir black oil model with $50 \times 35 \times 20$ dimensions in I, J, and K, respectively, with a total block count of 35,000, was built as shown in Fig. 4. The reservoir depth is 1,400 m with water oil contact (WOC) located at 1,750 m. The reservoir average porosity is 25% with a permeability of 70, 119, and 7,000 milli-Darcys (mD) in the I, J, and K directions, respectively. The other reservoir parameters and properties used in this study are provided in Table 2. The voidage replacement ratio (VRR), which is defined as the ratio of injected fluid to produced fluid, measures the rate of change of reservoir energy (BaniHammad et al. 2019). Because of its great influence on the displacement process and on maintaining the reservoir pressure

**Table 2.** Clair ridge reservoir characteristics

| Parameters | Symbol | Value | Units |
|---|---|---|---|
| | Formation properties | | |
| Reservoir depth | D | 1,400 | m, subsea |
| Oil water contact | OWC | — | m, subsea |
| Closure | A | 220 | $km^2$ |
| Net pay | $h_n$ | — | m |
| Total pay | $h_t$ | — | m |
| Permeability | K | 70–119–7000 | mD |
| | Fluid properties | | |
| Bubble point pressure | $P_b$ | — | bara |
| Solution GOR | $R_s$ | 68 | $m^3/m^3$ |
| Oil gravity | $\rho_0$ | 24 | degrees API |
| Formation volume factor | $B_0$ | — | Res vol/std vol |
| Oil viscosity | $\mu_0$ | 3.2 | cP |
| Sulphur content | — | 0.44 | mol % |
| | Reservoir | | |
| Temperature | $T_R$ | — | °C |
| Initial pressure | $P_i$ | 244.7775 | bara |
| Oil initial in place | OIIP | 1.3 | $Bm^3$ |

at its initial state, conventionally it is maintained close to one. To keep it close to one, instantaneous VRR is accomplished by using production data to determine the fluid to be injected (Temizel et al. 2016). If the VRR is one or more, it implies that the reservoir pressure is maintained by injected fluid, whereas if the VRR is less than one, it means the reservoir pressure has declined. In this simulation study, the VRR effect on cumulative oil production was analyzed. In the model, there were four added wells: one horizontal producer well, one vertical producer well, and two injector wells. The plan was to find optimal well locations for the added wells so as to increase oil production. Furthermore, the optimal well operational parameters were determined so as to maximize NPV.

### *Rock Fluid Properties*

Oil water relative permeability is an important data point for reservoir modelling and simulation, as it offers a relative movement status of reservoir fluids within the region. Also, it exerts a great influence on water flooding during water injection. In this paper, a mathematical model (the DW relative permeability model) was used to estimate the oil water relative permeability from resistivity logs (Bian et al. 2020), while capillary pressure was estimated by a robust hysteresis modeling method (Yoon et al. 2020). The oil water relative permeability and capillary pressure curves are shown in Figs. 5(a and b), respectively. The PVT properties of reservoir fluids also play a vital role during reservoir modelling and simulation, by setting suitable parameters. This helps with predicting production trends and reservoir management by predicting the reservoir fluids' behavior under different pressure and temperature conditions. Also, PVT data is important for surface designing facilities (El-Hoshoudy and Desouky 2019; Kargarpour 2020). In this study, the PVT data was estimated by using hybrid functional networks (Oloso et al. 2017). The PVT properties are shown in Fig. 6.

## Results and Discussion

After 10 years of production, the main objective function was maximized and optimal production constraints were determined. Any well operating outside of these production constraints was shut-in to minimize the operational costs. Most of the shut-in wells were affected by early water breakthrough due to existing fractures and extended faults in fields. These shut-in production wells can be either converted to injection wells so as to maintain the reservoir pressure, or do again well ompletion. Because of the fractures and extended faults, it is not economical to add a substantial number of new wells; this was proved by Harbour in March 2021, when it added nine new wells, with worse results.

Optimal production constraints that provide the best field net present value (FNPV) are shown in Table 3. Fig. 7 shows that, as the group injection rate and maximum water-cut increases, the FNPV increases. Also, the parameters infill injection 2 and infill horizontal producer have a positive influence on field NPV, whereas infill injection 1, and well 15 and 16 types have a negative influence on field NPV. This means that the group injection rate has a positive effect (main effect) on field NPV, while water cut has a negative effect (interaction effect).

The locations of four infill proposed wells, which are infill horizontal producer, infill vertical 1 injection, infill vertical 2 injection, and infill vertical producer, are summarized in Table 4.

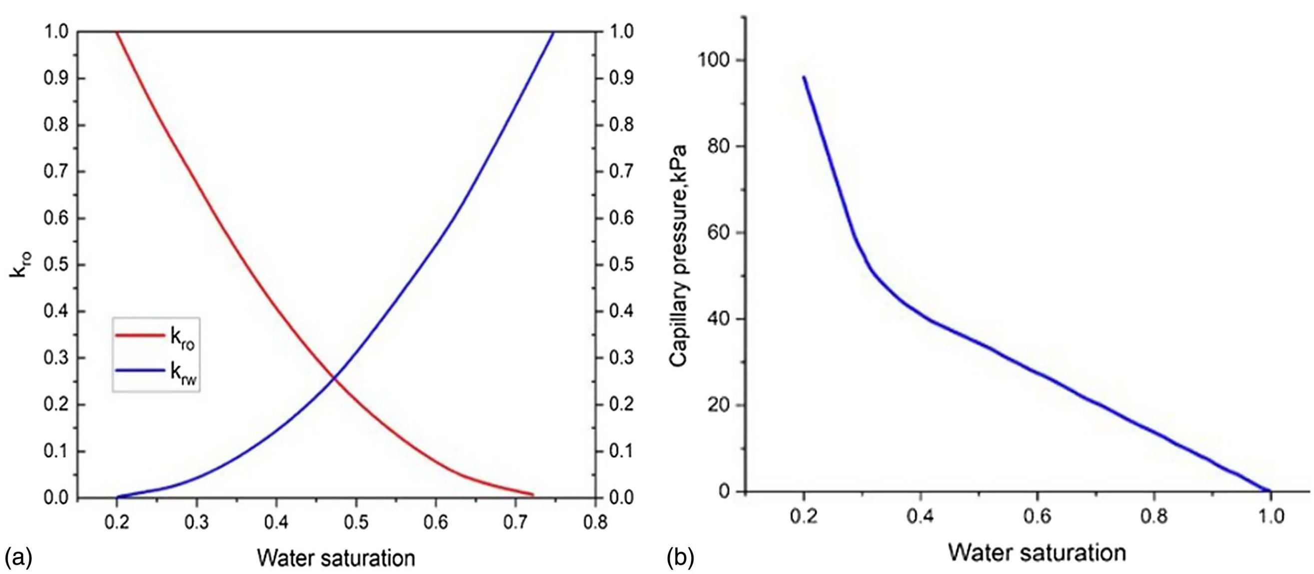


**Fig. 5.** (a) Relative permeability curve (water wet); and (b) capillary pressure curve.

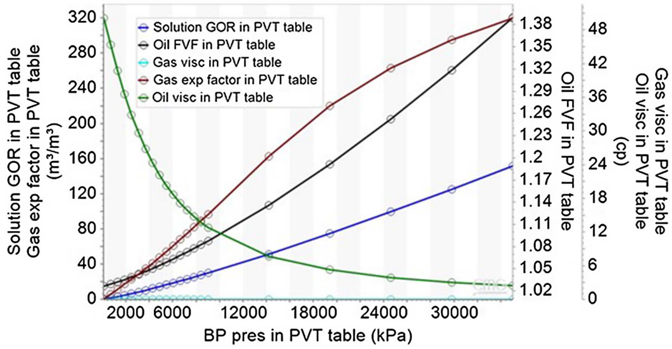


**Fig. 6.** PVT properties.

**Table 3.** Summary of optimal operational parameters

| Operational parameter | Optimal value | Unit |
|---|---|---|
| Group injection rate | 7,500 | $BBL/DAY$ |
| Maximum GOR | 840 | SCF/STB |
| Maximum water-cut | 88 | % |
| Minimum oil rate | 4,250 | STB/DAY |
| Well bottomhole pressure | 851.20 | psi |

### Pressure Distribution Effects along the Reservoir

Pressure—the main driving energy that influences fluid production from the reservoir—can be either natural, or the result of injection of fluids. Hence, it is crucial to configure and monitor pressure distribution in the reservoir before and during production in order to foresee other phases of field development, so as to maintain or increase production. Fig. 8 shows the pressure distribution before starting production, and Fig. 9 shows the pressure decline after 15 years of production. Then, after infill drilling optimization and water flooding, the pressure recovered (Fig. 10), and the production increased (Fig. 12). These results show the positive influence of added injection and production wells on recovering reservoir energy and maximizing production, respectively.

### Effects of Reservoir Heterogeneity

Reservoir heterogeneity is the variation in different layers of the reservoir (Khanfari and Fard 2017). The dissimilarity of these layers is because of different depositional mechanisms and environments within the strata. Reservoir heterogeneity can be either homogeneous or heterogeneous. One of the famous methods of determining reservoir heterogeneity is the Lorenz method, which involves computing the Lorenz coefficient (L). Its value ranges from 0 to 1. When the Lorenz coefficient is 0, it means the reservoir is homogeneous, whereas when it is 1, it means that the reservoir is heterogeneous. This shows that, as the Lorenz coefficient increases from 0 to 1, the homogeneity decreases and heterogeneity increases. L is determined by finding the area under the curve (area above the line of perfect equality) (Awaad et al. 2020; Correia et al. 2015; Khanfari and Fard 2017; Yang et al. 2017). And from the Lorenz curve, Fig. 11, the Lorenz coefficient was 0.9837, which indicates that the reservoir is heterogeneous. This indicates that the field is composed of various mineral components that differ from one layer to another in shape and size, and that reservoir properties such as permeability or porosity cannot be assigned a single value. Thus, this reservoir needs to be analyzed very carefully to avoid uncertainty. This was accomplished by the Lorenz curve in Fig. 11.

The Dykstra-Parsons' permeability variation (V) equation (Dykstra and Parsons 1950; Schmalz and Rahme 1950), as shown in Eq. (4), was also used to measure the field reservoir heterogeneity. The permeability variation was approximately 0.5, which

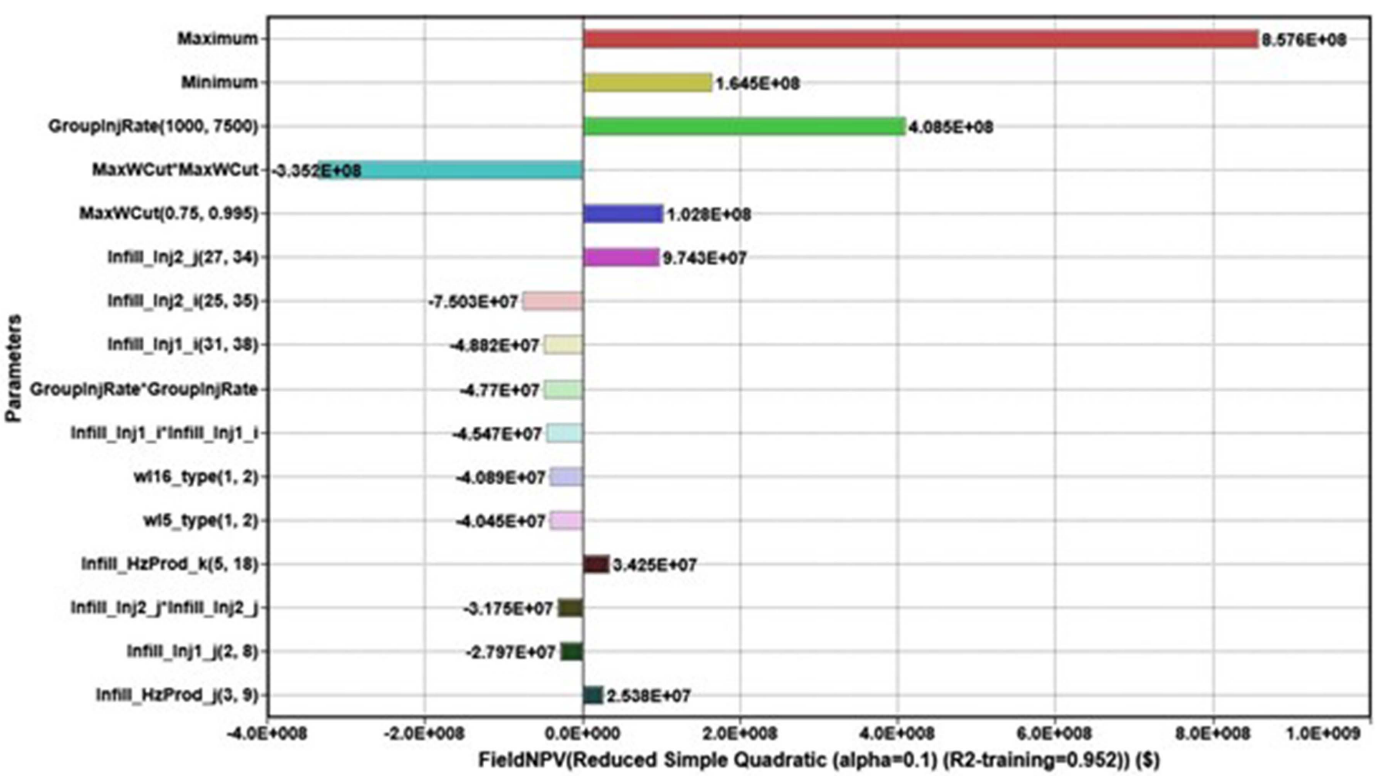


**Fig. 7.** Tornado plot for field net present value FNPV.

**Table 4.** Infill well locations

| Infill well name | Gridblock location |
|---|---|
| Infill horizontal producer | (28,9,17) |
| Infill vertical injection 1 | (33,2,14) |
| Infill vertical injection 2 | (25,34,7) |
| Infill vertical producer | (36,9,10) |

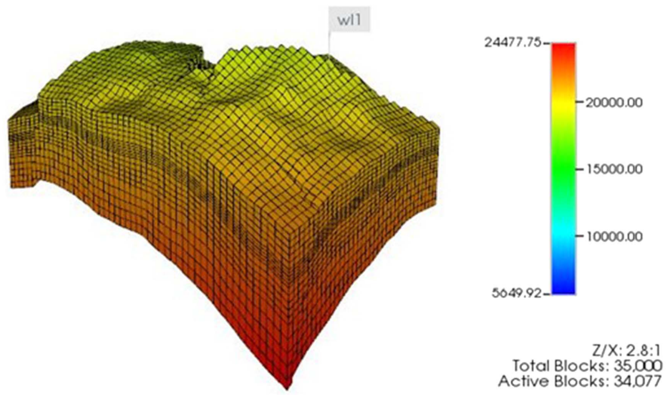


**Fig. 8.** Reservoir pressure (kPa) distribution before starting production.

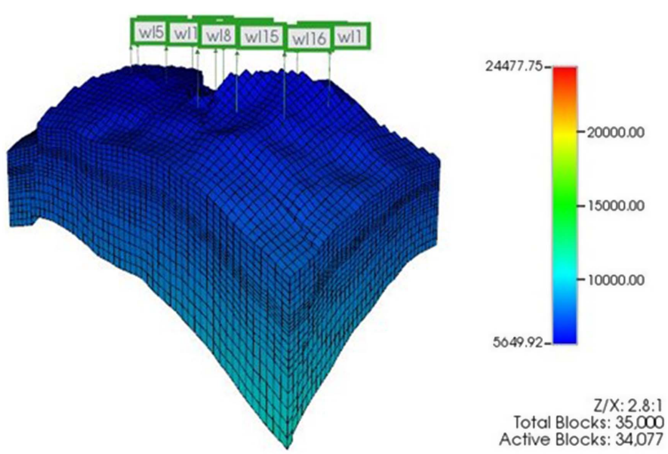


**Fig. 9.** Reservoir pressure (kPa) distribution after 15 years of production.

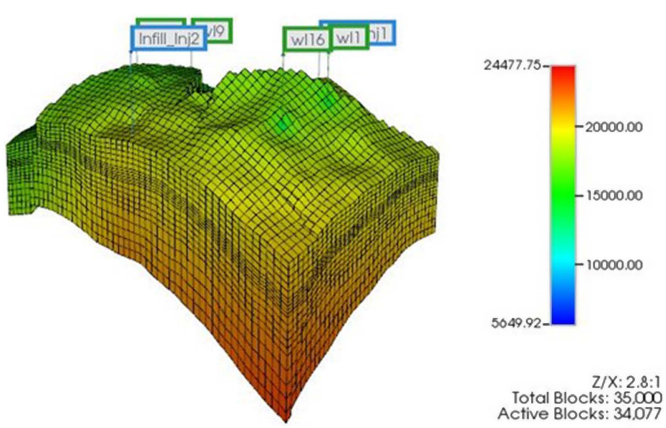


**Fig. 10.** Reservoir pressure (kPa) distribution after water injection by properly placed infill wells.

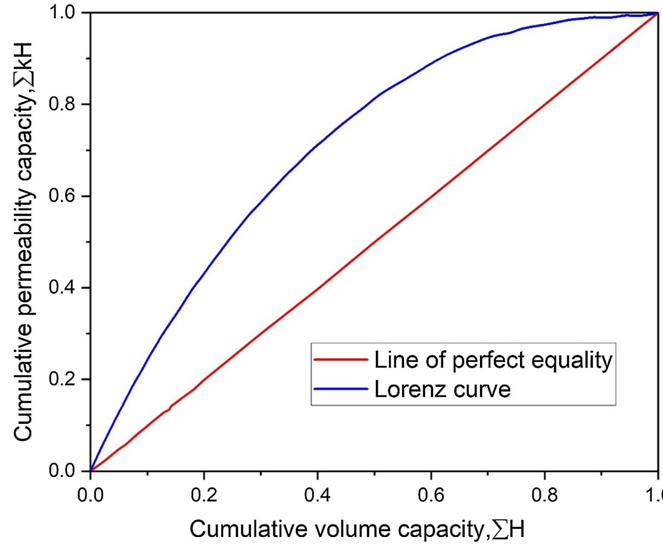


**Fig. 11.** Lorenz coefficient for the Clair Oil Field.

indicates that the reservoir is heterogeneous. This agrees with the Lorenz curve, which reveals that the reservoir is heterogeneous

$$V = \frac{k50^{th} - k84.1^{th}}{k50^{th}} \tag{4}$$

where $k50^{th}$ is the median permeability (mD); and $k84.1^{th}$ is the permeability value at one standard deviation (mD).

### *Cumulative Oil Production with and without Infill Wells*

The entire field's cumulative oil production with and without infill wells is shown in Fig. 12. The cumulative oil production was approximately $7.91 \times 10^6$ and $9.39 \times 10^6$ $m^3$ without and after infill wells, respectively, as shown in Fig. 12. This was an increment of 18.7% in cumulative oil production after infill drilling optimization, adding two production wells and two injection wells. The proper location of the four added wells has a great impact on the cumulative

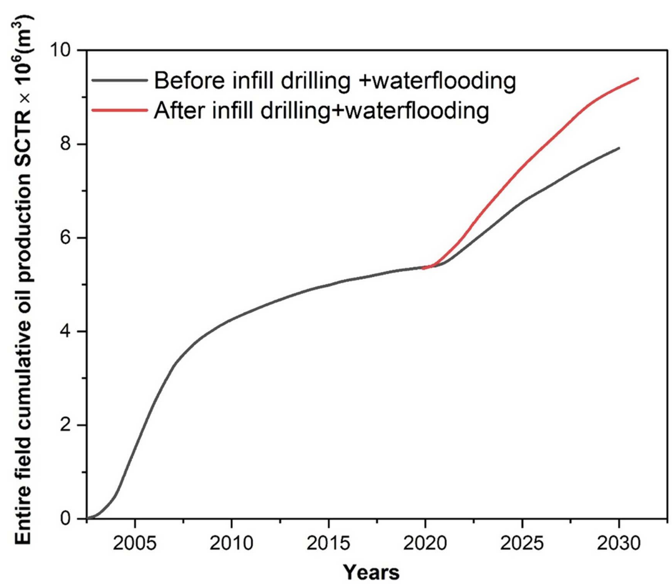


**Fig. 12.** Comparison of entire field cumulative oil production.

oil production increase by changing the well pattern and increasing well density, which reduces the average well spacing. The two injection wells helped to increase the reservoir energy, which pushed the oil towards the production wells, whereas the horizontal production well helped to produce oil from virgin zones and poorly swept areas. The horizontal well also helped to reduce the heterogeneity of the reservoir, because it covered a larger area and reduced the distance that oil had to travel to the wellbore, thus changing the paths of formation fluid flow. Furthermore, the infill wells improved the continuity between injection and production wells.

### *Effects of Vertical to Horizontal Permeability Ratio ($k_v/k_h$) on Cumulative Oil Production*

In this paper, the minimum $k_v/k_h$ ratio value used was 0.001 and the maximum was 0.8. The other $k_v/k_h$ values were 0.01, 0.1, 0.6, and 0.7. The results revealed that, as the $k_v/k_h$ ratio increased, so did the cumulative oil production. This was due to the fact that the increase in the $k_v/k_h$ ratio improved waterflooding sweeping efficiency by increasing fluid transmissibility, crossflow, and communication between the vertical and horizontal layers of virgin and depleted zones. Furthermore, the increase in the $k_v/k_h$ ratio reduced the heterogeneity problems in the reservoir, which as noted previously can result in lower production. Fig. 13 shows the effect of $k_v/k_h$ ratio on cumulative oil production.

### *Effects of VRR on Cumulative Oil Production*

VRR is a very important parameter in waterflooding projects. It shows the relationship between injected fluids and produced fluids. It measures the amount of fluids to be produced by recovering declined reservoir energy through injected fluids (BaniHammad et al. 2019). VRR can be calculated in real time (instantaneously) in the field from the produced and injected fluids over a specific period of time, either monthly or daily. Also, VRR can be calculated as an average by taking the cumulative produced fluids, cumulative injected fluids, and average GOR (Awaad et al. 2015; Brice et al. 2014; Vittoratos et al. 2011). Mathematically, VRR is expressed as

$$VRR = \frac{\text{Injected reservoir volume}}{\text{Produced reservoir volume}} \tag{5}$$

$$= \frac{B_{winj}(I_{Winj}) + B_{ginj}(I_{ginj})}{B_o(Q_o) + B_{winj}(Q_W) + Q_O(GOR - R_s)} \tag{6}$$

For water injection, VRR is given as

$$= \frac{B_{winj}(I_{Winj})}{B_o(Q_o) + B_{winj}(Q_W) + Q_O(GOR - R_s)} \tag{7}$$

where $B_{winj}$, $B_o$, and $B_{ginj}$ are the volume factors for water, oil, and gas formation, respectively; $I_{winj}$ *and* $I_{ginj}$ are the injection rates for water and gas, respectively; GOR is the gas injection ratio; $R_s$ is the GOR dissolved; and $Q_o$, $Q_W$ are the rates of oil and water flow, respectively.

As shown in Fig. 14, a VRR = 0.7 recovers more oil than other voidage replacement ratios, including VRR = 1. This is because the mechanisms of waterflooding on heavy oil are different from those on light oil, where oil recovery increases as the VRR increases. In heavy oil waterflooding, there is emulsion formation that is accelerated by the shear forces of unmixed gases, because of incomplete VRRs (<1). As water in the oil emulsions grows, the areal sweep efficiency of injected water is stabilized and improved, as illustrated in Fig. 15. This oil in the water emulsion formation has a higher viscosity than heavy oil, and it enables the injected water to move edgeways to unemulsified heavy oil resulting in the widening of the water displacement front, as shown in Fig. 15. This shows that at the beginning of the waterflooding process, a VRR less than 1 is adequate to start operations, especially in heavy oil reservoirs.

### *Horizontal versus Vertical Infill Production*

Horizontal wells are wells drilled from the side of a vertical well, whereas vertical wells are wells drilled downward from the ground. In 2017 the number of horizontal wells first exceeded the number of vertical wells, and in 2018 horizontal well production in the US constituted approximately 96% and 97% of crude oil and natural gas production, respectively, from shale reservoirs (Gib Knight 2019). In the Clair Oil Field development, by combining infill drilling with water flooding, horizontal infill producers outperformed vertical infill producers by 5.5% (Fig. 16). The main reason is that infill horizontal producers occupy a larger reservoir drainage area (thus better overcoming the effect of fractures on well productivity)

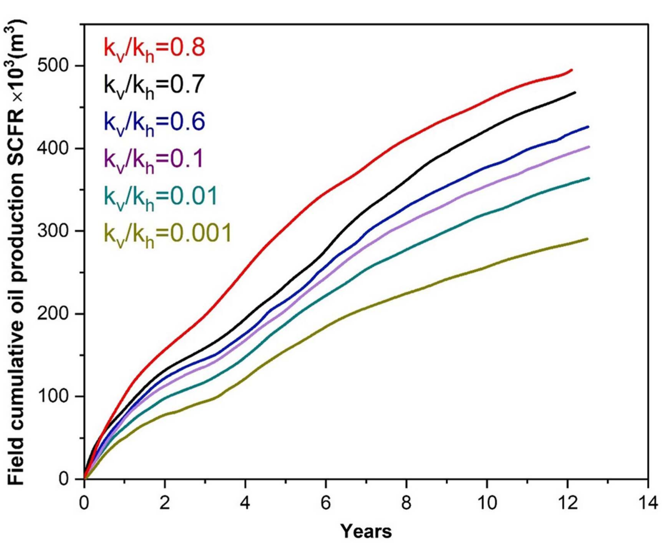


**Fig. 13.** Effect of kv/kh on cumulative oil production.

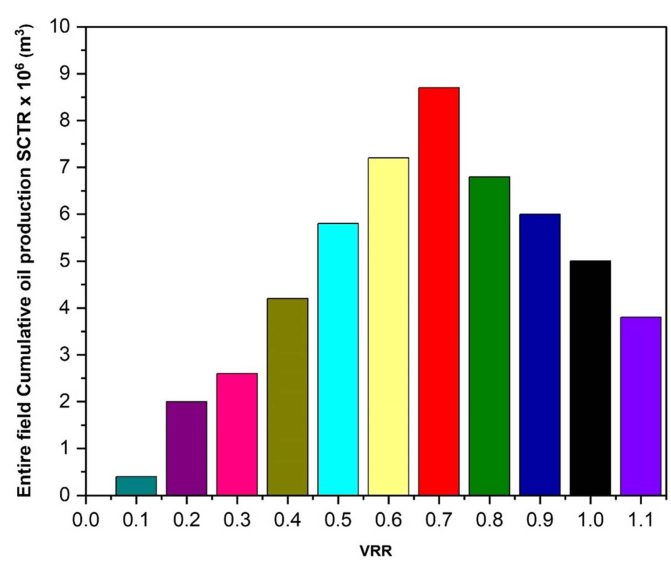


**Fig. 14.** Effect of VRR on cumulative oil production.

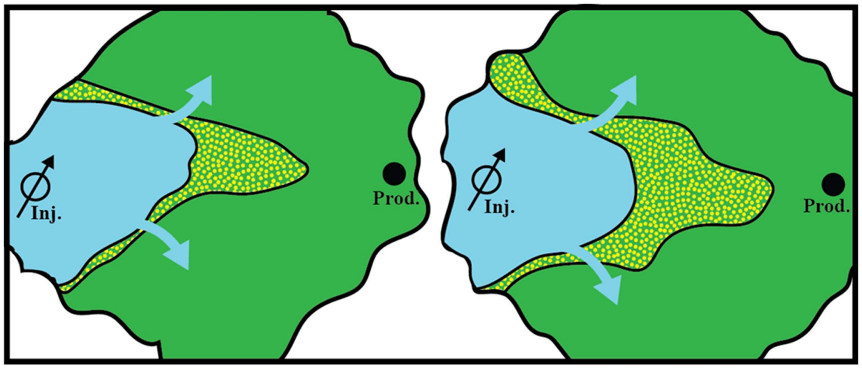


**Fig. 15.** Oil-in-water emulsion formation and displacement front effects during waterflooding in heavy oil.

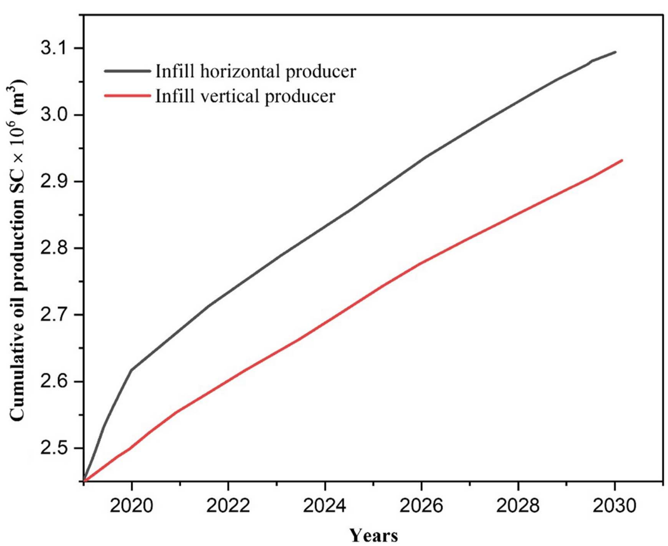


**Fig. 16.** Horizontal versus vertical infill effects on cumulative oil production.

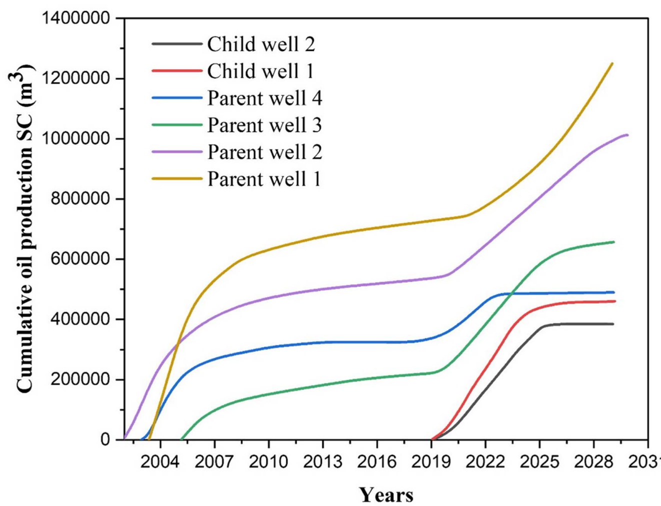


**Fig. 17.** Comparison of parent and child wells on cumulative oil production.

than do infill vertical wells. Also, infill horizontal producers have late water breakthrough and fewer sand production problems than do infill vertical producers. Furthermore, infill horizontal producer wells reduce the heterogeneity problem by increasing the plateau length to produce by-passed oil, virgin zone oil, and poor-flooded areas. This also confirms the dominance of heterogeneities in the vertical direction.

## Comparison of Cumulative Oil Production between Child and Parent Wells

Child wells are the wells added to the reservoir for the purpose of enhancing production, whereas parent wells are the existing wells in the reservoir before infill drilling (Manchanda et al. 2018; Syed et al. 2021). This paper evaluated differences in oil production performance between child wells and parent wells in the Clair Oil Field. The changes in production can be mainly attributed to interaction effects between the child wells and the parent wells. The factors that cause interference between child and parent wells are reservoir pressure depletion, effective stress changes, and total stress changes. Thus, parent well production changes the stresses and pressures around child wells. The fractures created by reservoir pressure decline and stress changes grow asymmetrically towards the child wells, creating a drainage area that changes the fluid flow paths. Therefore, the child wells record less cumulative oil production than the parent wells (Fig. 17).

## Economic Analysis

Because infill drilling operations incur costs and have an impact on ultimate oil recovery, understanding the economic limits of the existing project and the influence of infill drilling on the payout is very important for project evaluation. Then, economic analysis must be performed based on a discount rate, so as to observe project feasibility. In the case study area, this was carried out to examine the payout that can be obtained by infill drilling with waterflooding. The economic analysis started immediately after the infill drilling commenced. For the purpose of determining the optimal location of both injection and production wells, NPV was selected as the objective function to be maximized. Because of oil fluctuation prices, this paper assumes certain values used for economic analysis, as provided in Table 5. In this study, the NPV is the difference in net cash flow (NCF) between hydrocarbon revenues, water costs, operational expenditure (OPEX), and capital expenditure (CAPEX):

**Table 5.** Economic parameters used for NPV calculation

| Economic parameter | Value | Unit |
|---|---|---|
| Oil price | 60 | \$/bbl |
| Discount rate | 10 | % |
| Gas price | 3 | \$/Mscf |
| Water production cost | 3.5 | \$/bbl |
| Water injection cost | 3.5 | \$/bbl |
| CAPEX | 2 | MM\$/well |
| Drilling cost | 850 | \$/foot |

$$\text{Net cash flow} = \text{Hydrocarbons revenues} - \text{water cost} - \text{OPEX} - \text{CAPEX} \quad (8)$$

Hydrocarbon revenues include both oil and gas revenues, and water costs include both water production handling costs and water injection costs. Eq. (8) is expressed in terms of NPV by taking into account the discount rate shown in Eq. (9) (Davidson et al. 2006; Eshkalak et al. 2014):

$$NPV = \sum \frac{NCF}{(1+i)^t} \quad (9)$$

where $i$ is the discount rate; and $t$ is the time period.

The economic parameters and their values used for NPV estimation are provided in Table 5. The results revealed that infill drilling with waterflooding raised the NPV from \$5.555985 × $10^8$ to \$8.5756134 × $10^8$ (Fig. 18), a 54.4% increase. This shows that better economic returns are obtained by infill drilling if wells are well-placed.

## Conclusions

This paper shows that infill drilling optimization for enhancing oil recovery by waterflooding in the Clair Oil Field in the UKCS can provide notable improvements. The applied algorithm made remarkable advancements in objective function, production constraints, and optimal well location. This shows that the applied algorithm can be useful in developing and extending the life of an entire oil field. The following are the key points of this study:

- Enhanced economic returns were obtained by a combination of infill drilling and waterflooding. The NPV increased by 54.4% over the base case (\$5.555985 × $10^8$ and \$8.5756134 × $10^8$, respectively). The oil recovery factor increased from 17.2% to 20.2%, which reflects the better drainage after adding two injection wells and two production wells. The water cut was reduced from 95% to 88% and the GOR decreased from 1,000 to 840 SCF/STB. This shows the success of infill drilling optimization in the Clair Oil Field. The higher oil recovery rate will be obtained in areas of higher heterogeneity effects that will be drained by adding more production wells, mainly horizontal wells.
- Simulation studies have revealed that VRR effects for heavy oil reservoirs are different from light oil reservoirs, where VRR increases lead to an increase in cumulative oil production. This study has proved that a 0.7 VRR results in a higher cumulative oil production than do lower or higher VRRs. Also, the infill horizontal producer wells resulted in better production than the infill vertical producer wells. The production was estimated to be 3.09 × $10^6$ and 2.91 × $10^6$ $m^3$ for infill horizontal and vertical producer wells, respectively. This shows that the success of infill drilling depends on the type of infill well producer. Infill horizontal producers were a better option than infill vertical well producers.

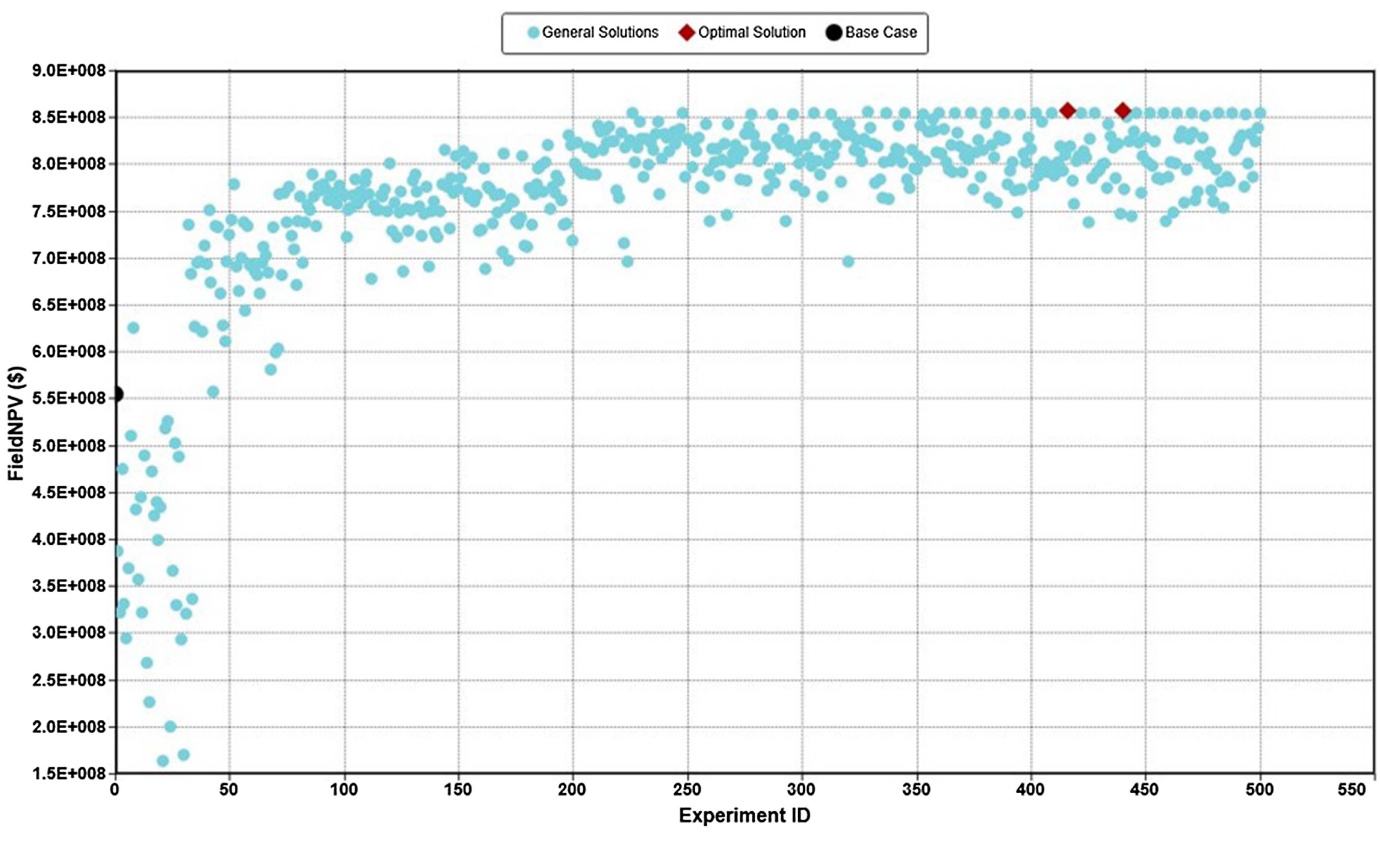


**Fig. 18.** Field base NPV and optimal NPV.

- After infill well optimization by waterflooding, parent well production outperformed child well production. This proves the presence of extended fractures and faults, which affect the production of child wells. The heterogeneity effects and poor sweep efficiency during waterflooding were reduced by the infill horizontal well. This is because of its long lateral plateau length, which covers a larger reservoir drainage area. This helps the mobilized oil travel a shorter distance to the horizontal producer well.
- There were many changes in reservoir pressure because of the waterflooding process. This indicates that waterflooding has an influence on increasing reservoir pressure and maintaining pressure drawdown. Simulation results revealed that infill drilling optimization by waterflooding has great potential for waterflooded projects, by enhancing oil production when other secondary and tertiary techniques have failed.

This study revealed that oil production in the Clair Oil Field can be substantially increased by combining infill drilling with waterflooding, after other improved oil recovery techniques fail. This study can be used as a benchmark for oil field developments having the similar geological locations and characteristics. The proposed operational optimal parameters for infill wells can be used as a base elsewhere in the world. However, a comprehensive feasibility study needs to be conducted before implementation. This is very important to avoid uncertainty and economic risks.

## Recommendation for Future Studies

It was expected that child wells would exceed production of parent wells. However, in the Clair Oil Field parent wells outperformed child wells, due to the presence of extended fractures and faults that result in early water breakthrough. For some unconventional reservoirs, this problem has been solved by refracturing the parent wells before stimulating child wells, which results in child wells outperformed their parent wells.

## Data Availability Statement

Some or all data, models, or code generated or used during the study are proprietary or confidential in nature and may only be provided with restrictions. Confidential data which can be shared with restriction are PVT data, bubble point pressure, temperature, formation volume factors etc. Other data can be shared without restriction.

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## Notation

*The following symbols are used in this paper:*

$B_o$ = oil formation volume factor ($rb/stb$);
$B_{ginj}$ = gas formation volume factor ($rb/stb$);
$B_{winj}$ = water formation volume factor ($rb/stb$);
$I_{winj}$ = water injection rate ($BBL/DAY$);
$I_{ginj}$ = gas injection rate ($BBL/DAY$);
$Q_o$ = oil flow rate ($BBL/DAY$);
$Q_W$ = water flow rate ($BBL/DAY$);
$R_s$ = solution gas ratio ($SCF/STB$); and
Scf = standard cubic feet.

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