Thermally-enhanced oil recovery from stranded fields: Synergy potential for geothermal and oil exploitation

Zaman ZiabakhshGanji[1], Marinus E. Donselaar[1], David F. Bruhn[1,2], Hamid M. Nick[3]

[1]Delft University of Technology, Stevinweg 1, 2628 CN, Delft, The Netherlands

[2]GFZ-Potsdam, Telegrafenberg, 14473 Potsdam, Germany

[3]Technical University of Denmark, Anker Engelunds Vej 1 Bygning 101A, 2800 Kgs. Lyngby, Denmark

email address of author: z.ziabakhshganji@tudelft.nl

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ABSTRACT

Production of oil and gas in the Netherlands is in a mature stage. Production decrease coincides with an increased interest in geothermal energy production as an alternative source of energy in the Netherlands. Deep geo- thermal projects target the same reservoir space as the oil and gas industry, with aquifers between 1500 and 4000 meters depth and a temperature range from 50 to 120 ºC. Focus of the study is on the Moerkapelle stranded heavy oil field in the West Netherlands Basin (WNB). Below this stranded field a geothermal reservoir with a temperature above 100 ºC is located. In the present study we demonstrate sensitivity analyses of the synergy potential of thermally-enhanced oil recovery, and geothermal energy using a 3-D two phase flow geological model. The model that accurately accounts for the pressure and temperature influences on the thermo-physical transport properties such as viscosity is applied for showing influences of the various effective parameters on the synergy potential for geothermal and oil exploitation such as injection temperature and reservoir heterogeneity. With this model it is shown that reservoir heterogeneity can reduce the efficiency of thermal heavy oil recovery factor.

1. INTRODUCTION

There is a broad consensus that most of the hydrocarbon reservoirs in the world, approximately 70% of total world oil resources, contain heavy oil, extra heavy oil, tar sand and bitumen that the current industry efforts are to find a proper way to obtain enhance oil producing of them (Farouq Ali 2003). High amount of the heavy oil viscosity, and hence slight mobility, plays an important role for oil producing from these reservoirs that should be reduced by some EOR methods. In such case, thermal recovery method is one of the most well-known methods which are typically implemented in many projects such as Steam stimulation, or cyclic steam flooding, also known as “huff’n’puff”, Steam flooding, Steam Assisted Gravity Drainage (SAGD), In-situ combustion, or fire flood, Hot Water flooding, Steam and Hot water injection, and Surface mining and thermal extraction (Teodoriu et al. 2007). Many authors (Teodoriu et al. 2007; Taber 1998) indicated that the most effective methods are steam flooding and hot water flooding by increasing in the recovery factors about 20 to 30%.

Several factors control the dynamics of multiphase flow into oil/geothermal reservoirs, including capillary trapping (Spiteri et al. 2008); density and viscosity variations (Saeid et al. 2014); porous and fracture media heterogeneity (Matthai and Nick 2009); fluctuations in injection temperature (Saeid et al. 2014); phase changes (Salimi and Wolf 2012); and the chemistry of the formation fluid and rock present in the system (Nick et al. 2015). Prediction of transport processes in highly heterogeneous systems is difficult due to the complex spatial correlation structure and the large variations of permeability and porosity.

Heavy oil reservoirs where hot waterflood processes have been applied for a long time reach economic cutoffs resulting from high water cut (Alajmi et al. 2009). The energy (heat) of hot water derived from rocks and fluid of deep aquifers that is known as geothermal energy. Based on the oil and gas sedimentary basins theory, usually deep aquifers, as a candidate for geothermal project, exist in oil and gas formation. Furthermore deep aquifers which are located (for instance in this work) beneath of the oil and gas formations are important for developing and utilizing geothermal energy in the oilfield because knowledge of the reservoirs generally is quite extensive due to the large amounts of data acquired during the exploitation stage. Moreover using of the geothermal energy has the potential to increase the oilfield’s life and leads to its ultimate oil recovery enhancement. Therefore, a “win-win” project might be appeared due to utilization and implementation of geothermal resource in oilfields.

Apart from the usage of geothermal for enhance heavy oil recovery, direct-uses of the geothermal resources that is applied widely in agriculture and district heating and electricity generations are ways of utilizing the produced heat from geothermal resources. Although the electricity generation conventionally requires high enthalpy resources (more than 150 ˚C) to power turbines, however, Gupta and Roy (2007) studied and suggested that low enthalpy resources might be useful to generate electrical power.

The aim of the present study is to assess and develop new strategies for integration geothermal energy with heavy oil production of the Moerkapelle stranded oil field in the West Netherlands Basin (WNB). Below this stranded field there is a geothermal reservoir with a temperature above 100 ºC. Therefore the geothermal technology might be conducted for enhanced Moerkapelle heavy oil recovery due to the higher heat content carried by hot water and the lower heat loss along the wellbore. This EOR method has several distinct advantages, such as reducing heat loss at surface and in wellbore, avoiding cold damage to the formation caused by low-temperature injection water from surface and decreasing energy consumption and environmental pollution (fig.1).

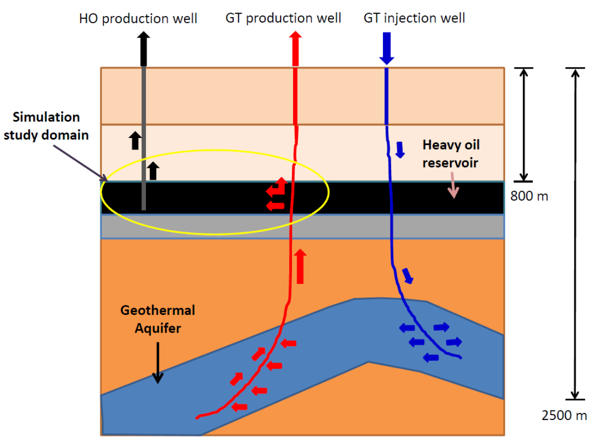

Figure 1: A schematic representation of the model study (in this figure HO is heavy oil and GT is Geothermal).

For this purpose a coupled heat and mass transfer models (ECLIPSE 300) was utilized to investigate the energy production from geothermal and also from heavy oil reservoir. In this study, we present a sensitive analysis and identify the key parameters such as heterogeneity of the reservoir the injection rate and temperature. This is performed to demonstrate how these parameters could control the ultimate heavy oil recovery factor and sweep efficiency.

2. HEAT DEMAND IN GREENHOUSES CULTIVATION AND GEOTHERMAL HEAT GENERATION

The energy demand in greenhouses, glass houses, agriculture is not a precise process. However the heat demand is much more depending of the crop and other ways of energy providing, such as assimilation lights and also isolation with screens and covers. Moreover, improved insulation and reduced ventilation are therefore the first steps towards creating energy-conserving greenhouses (FAO 2013). Bot et al. (2005) pointed out that the average energy demand is about 36.7 cubic meter of natural gas, as fossil fuel energy uses, per square meters of a greenhouse.

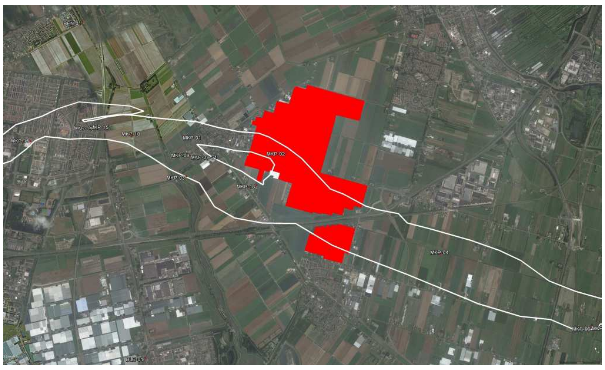

Figure 2: Greenhouses agriculture (red boxes) around the Moerkapelle oil field (white lines).

Around the Moerkapelle there are many greenhouse cultivation that consume energy for growing the crops. Figure 2 illustrates the greenhouses (boxes in red colour) area around the Moerkapelle oil field. The total area of greenhouses around the Moerkapelle oil field is approximately 3.46E6 m^2 and requires about 126 million m^3 of natural gas per year. Knowing that the energy provided by one m^3 of natural gas burning is approximately about 31.5 MJ. Therefore, for the greenhouse area the energy required is about 3.97 PJ per year. This amount of energy can be provided by the thermal energy which is extracted from a geothermal reservoir. The energy production by a geothermal doublet can be calculated through Equation [1].

$$\Delta \dot{E}_i = \dot{m}_i c_p \Delta T_i \qquad [1]$$

where $\Delta \dot{E}_i$ (J/year) is the annual thermal energy extracted in the i^{th} year, $\dot{m}_i$ (kg/year) is the total mass production of hot water in the i^{th} year, c_p (J/kg ºK) is the specific heat of the circulating fluid and ΔT_i (ºK) is the temperature difference between the produced and injected in the i^{th} year. By knowing the average reservoir temperature (here 100 ºC) for the geothermal aquifer, we assume injection temperature is 30 ºC. Based on the temperature difference and with assuming each doublet may be operated with a discharge of ~4800 m^3/day, the total energy provided of each geothermal doublet can be estimated of 0.51 PJ per year. Thus approximately 7.735 doublets might be needed to supply the heat requirement for all the farms.

3. MODELLING APPROACH

The Moerkapelle field (white lines in Figure 2) located about 15 kilometers northeast of the TU Delft area and is a heavy oil field with the Delft Sandstone at a depth of about 800-1000 meter. Petrophysical analysis of the logs from the Moerkappelle wells provided average properties for the Delft Sandstone which are listed in Table 1.

Table 1: Petrophysical analysis of the Moerkappelle oil field

Properties	Value
Average reservoir porosity	0.18
Average reservoir permeability	495 mD
Reservoir thickness	30 m
Initial oil saturation	0.83
Initial solution GOR	16 m^3/m^3
Initial reservoir pressure	8.96 MPa
Initial reservoir temperature	37 ˚C

The model contains two sets of well that one set is used to produce heavy oil from a depth of approximately 800 meter and another as injector (as producer in geothermal doublet) of hot water. This water could be provided from a geothermal reservoir, for instance Delft Geothermal Project (DAP), beneath of the Moerkapelle oil field before (and after for injection temperature control) transported to the surface and pumped through a heat exchanger for energy extraction purposes. In the Netherlands the geothermal gradient is about 3°C per 100 meters which is verified by TNO study (Simmelink et al. 2007) on the Den Haag Geothermal project resulting in a specific temperature gradient (Smits, 2008). Thus the reservoir temperature for the heavy oil zone is estimated using this Den Haag relation (Smits, 2008).

Unfortunately, there is not access enough information data of the reservoir fluid properties. Therefor to make a good prediction, the reservoir fluid data from analogue, heavy oil, fields in the world are used. Some missing data, by assuming validation by the oil and gas community over years, was adapted from the Fourth SPE Comparative Solution Project, problem 1 (Aziz et al., 1987). As observed in the initial analysis with single injector and producer, implementing hot water floods with the maximum injection temperature of 200 °C did not significantly increase the recovery factor after several years. Thus in order to evaluate the EOR impacts of hot water injection with various temperatures, we follow the third pattern of Torabi et al. (2012) which is include four injectors and four producers with a spacing of 67 m between each well. The size of reservoir model, as base case scenario of the model, was considered 500 x 500 m^2 (discretisation in 30 x 30 x 6 grid cells as course grid for run time limitation) with surface dimension and 30 m in thickness. Rock in each grid cell was assumed to has the isotropic and homogenous properties. Thermal properties including thermal conductivity and heat capacity of rock were also assumed to be homogeneous but different from the cap and the base rock. Table 2 summarizes grid thermal properties used in the base case model.

Table 2: grid thermal properties assigned in the base case model

Thermal conductivity ($W.m^{-1}.K^{-1}$)	
reservoir Rock	3
Oil phase	0.18
Water phase	0.67
Overburden	2.2
Underburden	2.2
Volumetric heat capacity ($J.kg^{-1}.K^{-1}$)	
Reservoir Rock	980
Oil phase	2012
Water phase	4190
Overburden	920
Underburden	920

Here, the relative permeability data derived from the Brook and Corey correlation are listed in Table 3 and shown in Fig. 5. In this study, the capillary pressure is neglected. And also it should be noted that, the effect of temperature (Hamouda and Karoussi 2008) on relative permeability was not modelled here and it is more desirable to investigate its effects in the future work.

Table 3: relative permeability parameters used in this study (van Balen et al., 2000)

Coefficients	Value	Coefficients	Value
S_{wi}	0.17	k_{roiw}	0.4
S_{orw}	0.05	k_{rwro}	0.1
S_{org}	0.1	k_{rgro}	0.2
S_{gc}	0	S_{wir}	0.17

Viscosity and density are important physical properties of crude oil. However, no practical theory exists for the calculation of these properties for heavy oil at elevated temperatures. In this study, heavy oil density was predicted from API and temperature, and then the predicted values of the viscosity were used in the next step to develop the fluid model.

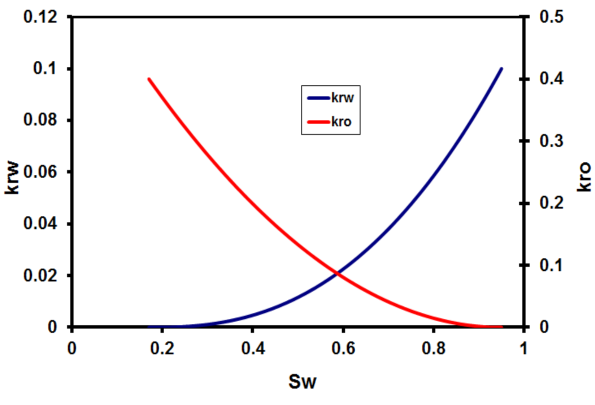

Figure 5: relative permeability curves verses water saturation

Fig. 6 shows the regression results and compares the experimental data with calculated values of viscosities and densities at different temperatures in ºC.

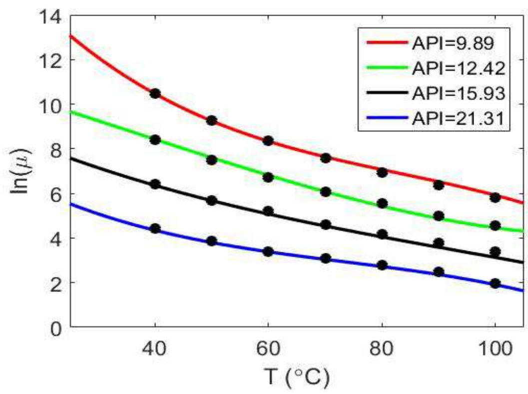

Figure 6: comparison between calculated viscosity (solid lines) after regression analysis with the experimental (symbols) data (EBN 2013)

4. MODEL SET UP

The energy balance and the continuity model equations (conservation of mass), including heat loss rate to overburden and underburden and pressure and temperature dependency of fluid properties, were solved by using a non-isothermal numerical reservoir simulator in a 3-D Cartesian domain. It is assumed that the reservoir model is at the depth of 800 meter and its temperature is estimated to be equal to 37 ºC and also all the cation concentrations in the reservoir are in an equilibrium state with reservoir rocks. The model contains 4 horizontally injectors and 4 producers that are extended in x-direction through third layer from reservoir tops. Furthermore, the wells are located in parallel form with a spacing of 67 meter (4 cells in x-direction) between each well. This is useful since it renders the impacts of injection water temperature on the displacement efficiency compared to that achievable from conventional water flooding schemes clearly visible as well. In order to achieve the objectives of this paper, two scenarios were used for: (a) homogenous media; (b) ,and, heterogeneous media with different net to gross (35%, 50% and 65%) generated by Flumy software which is an advanced process-based simulator of water and sediment transport developed by Ecòle des Mines in Paris (Grappe et al. 2012). For both scenarios hot water with various temperatures, starting at reservoir temperature (37 ºC) up to 200 ºC, were injected through injectors for 10000 days. Heat dissipated into reservoir fluid and rock through hot water injection in injector wells by various discharges (injection rate) and, hence, oil can be produced through producers due to viscosity reduction. The considered injection rates are 79.5, 156, 238.5 and 318 m^3/day (500, 1000, 1500 and 2000 BBL/day in field unit) of each injector by maximum 17.24 MPa (2500 Psia) well bottom hole pressure as injection well constrains. We assumed that water phase is in liquid and can be applied continuously without well integrity problem in the case of unconsolidated sandstone in the entire injection period. The producers were controlled with the bottomhole pressure of 0.7 MPa (100 psia) and the target rate is 156 m^3/day. It's worth mentioning that retaining of the water production rate at minimum is one of the main issue of the production well constraint (e.g. economical options). However water is injected as much as possible without exceeding the maximum water cut constraint.

5. RESULTS AND DISSCUSSION

5.1 Homogenous porous media

Before presenting results which document the impact of injection temperature and, also, rate on heavy oil RF, in this section it is first shown how the well spacing between injectors and producers can effect on oil recovery factor. In other to investigate this parameter we develop a simple model including an injector and a producer which are located approximately 417.5 m apart (Fig. 7).

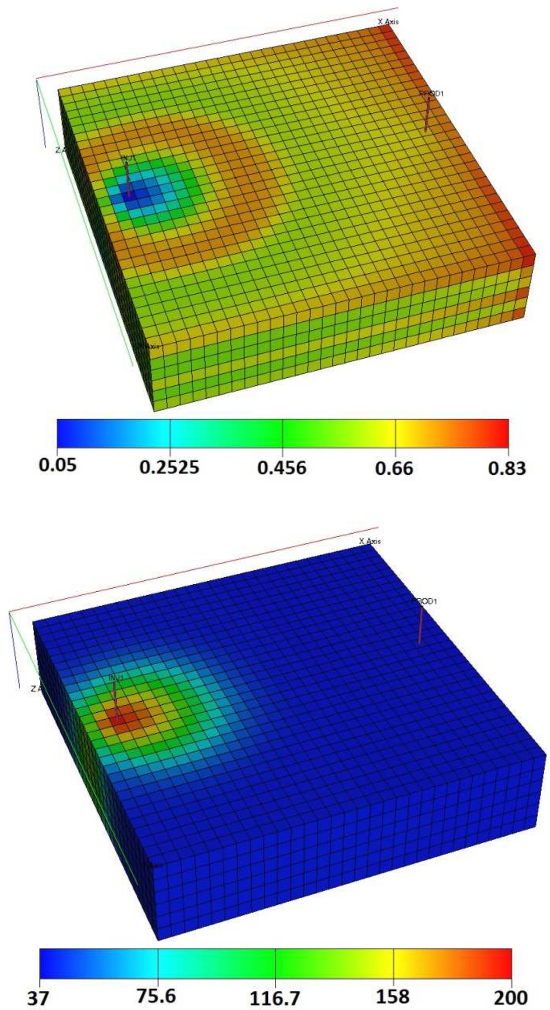

Figure 7: Oil saturation (top panel) and temperature distribution in °C (bottom panel) for a simple model after 10000 days hot waterflooding.

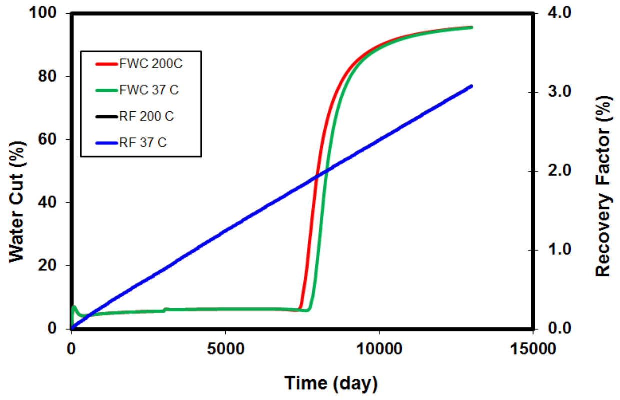

Figure 8: Water cut (FWC) and oil recovery factor (RF) obtain from a simple model with 79.5 m^3/day hot waterflooding.

As shown in figure 8 which represents schematic of this model, we allowed the production wells to perform as natural depletion for 3000 days by rate of 156 m^3/day and then implementing hot water floods with the maximum rate of 79.5 m^3/day and a maximum injection temperature of 200°C did not significantly enhance the oil recovery factor after 10000 days. One of the key issues of the hot water - flooding process, is temperature distribution achievement around the producers. In long interval between producers and injectors, the high temperature profile does not arrive to the producers and hence the oil viscosity reduction just happen around near of the injectors. In other word oil saturation alteration near the producers was not observed. As a result, efforts are ongoing to improve the temperature distribution and allow the heat to reach the producing wells, enabling production of oil with reduced viscosity. This might be occurred by reducing the distance between injectors and producers. However, should be noted that, in such case the high water cut may provide another challenge of hot water flooding. Therefore highlighting what variables could potentially improve the temperature distribution and ultimate recovery factor is desirable.

Figure 9 displays predicted recovery factors profile for both various temperatures and rate injection. The curves depict the behaviour after 10000 days of continuous injection.

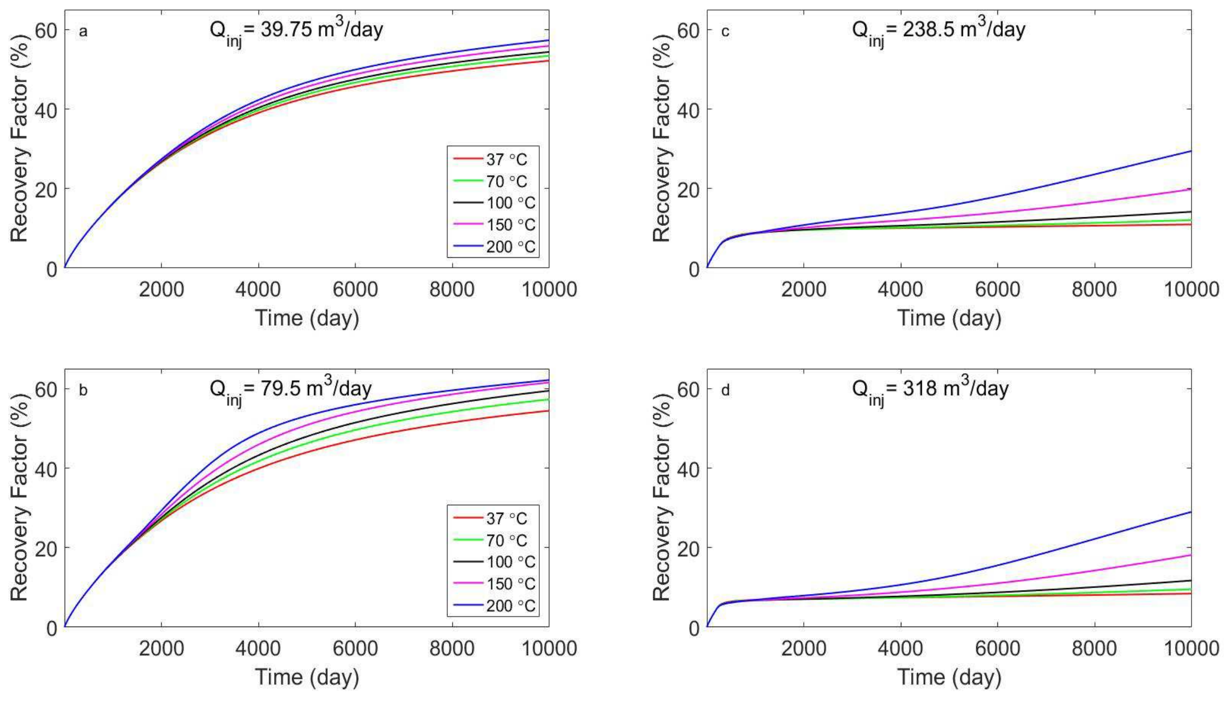

Figure 9: analysing the effect of the injection temperature and rate on oil recovery factor for 4 injectors and 4 producers model relate to figure 4 with production rate of 156 m^3/day.

The right-hand side panels (Fig. 9a, b) show that the recovery factor are slightly affected by the temperature of the water injection when injection rate is lower than production rate (156 m3/day) at each well. In other word comparison with the conventional water flood (37 °C) curve shows that by increasing the injection temperature up to 200 °C the recovery factor has been enhanced only by (~5%). Moreover the recovery factor is approximately high even with conventional water flood due to water breakthrough time reduction. It is further observed that in fig. 9b as the injection rate increases (still less than production rate), the RF slightly enhances of ~5 % and results similar to figure 9a still remained. Noted that, as seen in fig. 8b, about 3000 days after injection oil recovery enhancement is observed due to injection temperature increasing. These effect might likely be related to heat advection regarding to the injection rate. The left hand side, by contrast, panels (Fig. 9c, d) demonstrate recovery factor prediction when the injection rate is more than production rate of the producers. Comparison between figures 9c and 9d shows that although the RF is highly sensitive to the injection temperature (20 % RF enhancement is observed by hot water (200 °C) flooding) but injection rate increasing does not effect on the recovery factor. Nevertheless the low RF of conventional water flooding might be related to the rapid water penetrating to the producers. As a results, injection rate increasing, when greater than production rate, not only the RF is not enhanced but also it leads to RF reduction remarkably because of the rapid water breakthrough. Overall, results show that at injection rate higher than the production rate the RF is rather insensitive to increasing the injection rate.

Fig. 10 shows results similar to that of Fig. 9 , but for equivalent injection and production rates. Based on the wellbore constrains, in the figure 10b RF enhancing is observed about of 12% for hot water injection by temperature of 200 ºC.

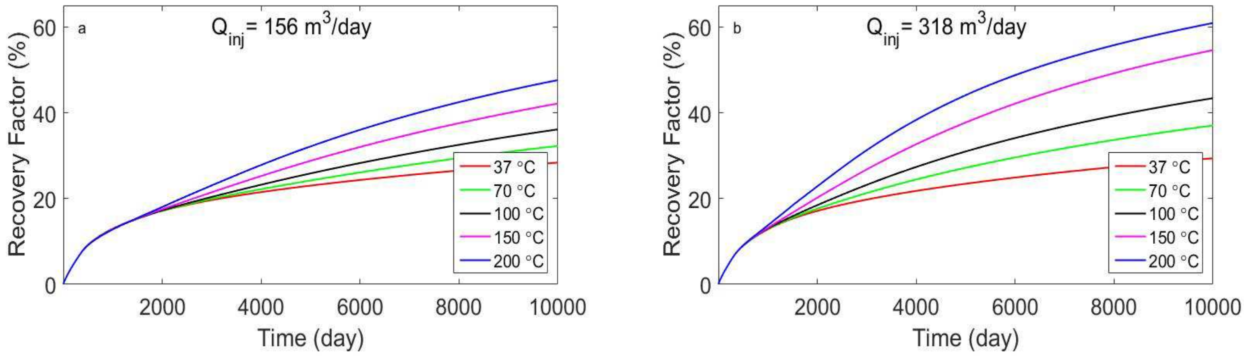

Figure 10: Recovery factor for different injection temperature and injection rates: a) 156 m^3/day b) 318 m^3/day.

In other word, it is observed that more oil is produced for a period of time for the injection rate of 318 m3/day. Moreover higher rates swept the reservoir of producible oil in a shorter time (almost half ratio here) than the lower injection rates and also better maintained the pressure after breakthrough occurred. It might be a possible reason to mention that higher rates lead to more advection mechanism and can help to heat distributes throughout reservoir to reduce the oil viscosity.

5.2 Heterogeneous porous media

Considering non-isothermal flow in a heterogeneous porous media, a series of simulations on several heterogeneous reservoir is conducted to examine the effect of heterogeneity together with temperature and rate alteration on the heavy oil recovery factor. For this purpose we use Flumy software to generate heterogeneity base on net to gross of the reservoir geology. The Flumy modeling results is calibrated to an extensive data set on depositional patterns. The simulation output provides synthetic stratigraphy and is used to set up models of reservoir architecture (Willems et al. 2014).

For generating of permeability and porosity distributions we have used the combination of extracted data from core analysis results of Moerkapelle field such as average permeability and the model architecture derived from Flumy modelling. (Henares et al. 2014; Donselaar et al. 2015; Veldkamp et al. 2015). This step is simplified and translated for incorporation in Eclipse 300 reservoir simulator.

Figure 11 illustrates the heterogeneous of the reservoir properties (permeability and porosity for 65% net to gross (N/G). It worth mentioning that the minimum porosity and permeability for instance shale rocks are assumed of 0.05 and 0.1 mD respectively (fig. 11).

Figure 12 displays effect of various net to gross on recovery factor between conventional water flooding and hot water flooding (100 ºC). It is known that the dispersive behaviour of two phase flow is a function of scale, correlation length and heterogeneity (Berkowitz et. al. 2006; Nick et al. 2015). Moreover, if the viscosities or densities of injection fluid and the formation fluid are different, both porous media and fluid properties control the dispersion (e.g. Nick et al. 2009; Nick et al. 2015). Therefore, variable dispersivity, early breakthrough times, and long tails of breakthrough curves are characteristic of such heterogeneous system. Here, the focus is on presenting the effect of net to gross of formation (heterogeneity) on non-thermal recovery of heavy oil reservoirs.

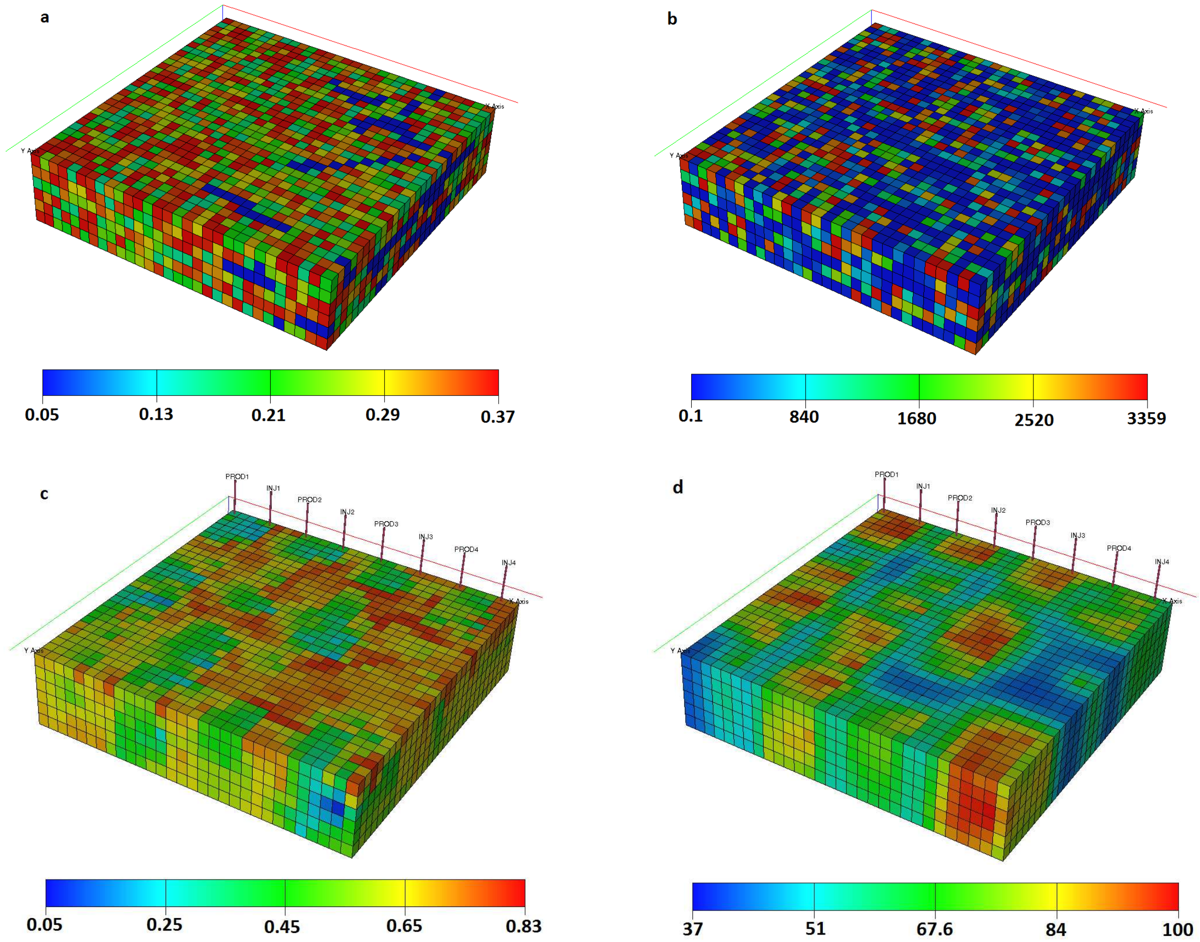

Figure 11: Schematic of a heterogeneous reservoir (65% N/G) for a) porosity distribution, b) permeability distribution (mD) c) oil saturation and d) temperature distribution (ºC) respectively after 10000 days with 318 m3/day hot water injection.

Figure 12 shows the recovery factor after 10000 days of operation in a homogeneous (Fig. 12d) reservoir and a heterogeneous reservoir. The average value of the permeability of the heterogeneous field is equal to the permeability of the homogeneous medium. Note that rate at the injection and production wells are kept constant (318 m^3/day) for the entire 10000 days of simulations. As seen in this figure thermal recovery factor of hot waterflooding seems to perform better than conventional waterflooding when the amount of degree of reservoir heterogeneity reduces. By contrast strong degree of heterogeneity (below 50% of net to gross) significantly effects on the heat distribution in the reservoir and hence leads to lowers RF. The possible reason might be likely acknowledged that the injected fluid tends to follow the high permeability channels and therefore heat is propagated in these channels. In this case the viscous crossflow process occurs (Zapata and Lake 1980; Nick et al. 2015) when the injected hot fluid from high permeable regions is diverted to low permeable regions due to the change of formation fluid viscosity induced by temperature changes. This behaviour leads to low recovery and delays the thermal effect to propagate to the displaced oil.

Overall, results show that heterogeneous media causes early breakthrough times for both conventional and hot water flooding in the reservoir resulting in oil recovery reduction.

5.3 The relative role of geothermal doublet

The results presented in the previous sections brought to light that hot water, that can be exploited from underground geological aquifer, flooding can enhance heavy oil recovery. Figure 10b shows as temperature increases up to 100 ºC, approximately 12% enhanced oil RF is observed. This means that about 158000 m3 extra oil can be produced from reservoir by 1272 m^3/day of hot water injection for 10000 days (Fig. 13).

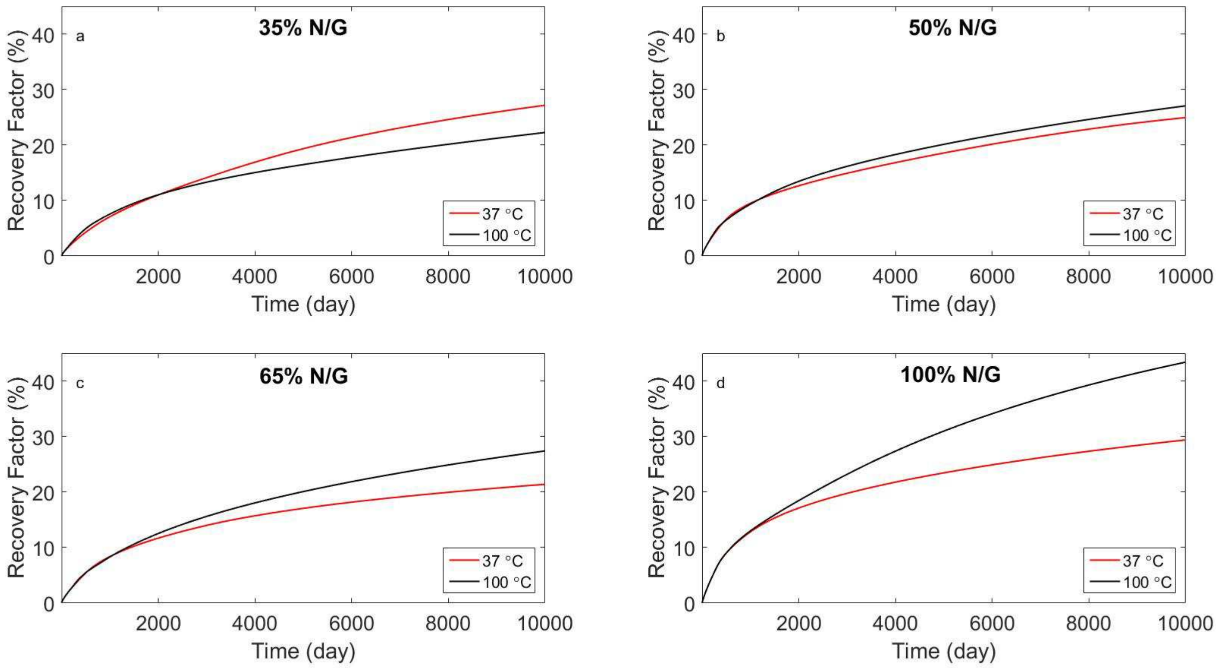

Figure 12: Comparison of RF between 318 m^3/day hot water and convention waterflooding for various amount of reservoir heterogeneity based on N/G.

By knowing the approximate energy released by burning one cubic meter of crude oil (~38.37 GJ) the total energy generated is calculated about 6.1 PJ after 10000 days. Thus the average energy per year is determined about 0.2226 PJ. Based on each doublet operation it should further be mentioned that this amount energy can derived by 0.265 of a geothermal doublet. It should be consider that burning of the fossil fuels can emit CO_2 and other undesirable greenhouse gases. These unfavourable gases can inject together with cold water in geothermal doublet as a promising way to avoid atmosphere pollution.

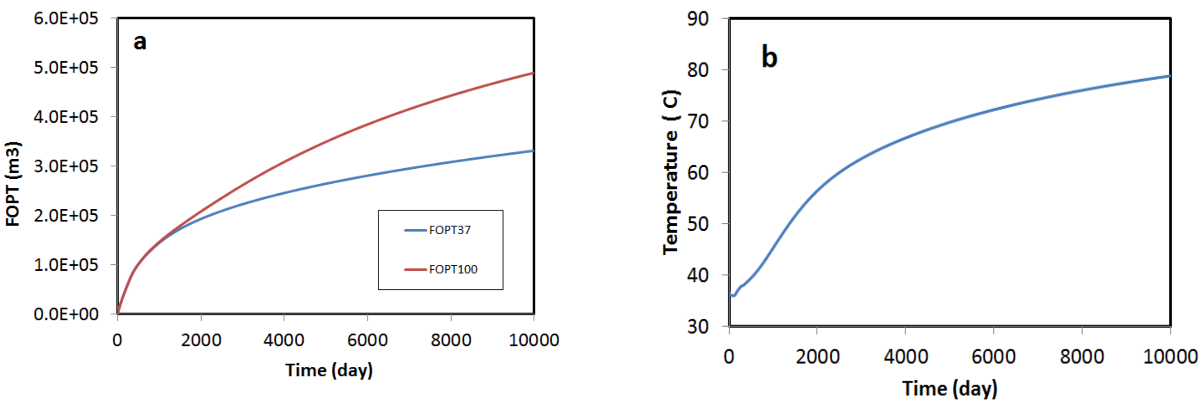

Figure 13: a) Cumulative total oil production of the model (m^3) b) temperature profile in production well number 4.

Apart from these items, the temperature profile of the production wells is catching the attention. As shown in figure 13b the temperature goes up and reaches about 80 ºC after 10000 days. Therefore it might potentially be another geothermal source choice. Furthermore, since the temperature drop in oil producers is not expected to be high (~20 ºC), it seems likely that consideration of these wells would potentially be other geothermal sources option.

Although these inferences from the model investigation are deemed fairly robust, the role of a number of processes, which were still simplified in the present analysis, would need further evaluation. Likely the most important of these is the optimum well location of injection and producers of a doublet and also oil production wells. This process should be expected to induce additional field operation costs.

3. CONCLUSIONS

In this work we proposed examining different thermal enhanced recovery strategies by utilizing the simple reservoir model for a sector of selected field (Moerkapelle). For this task, a non-isothermal transport modelling were conducted to handle the combined heat and multiphase flow simulations. We investigate the role of injection temperature, rate alteration of injection and reservoir heterogeneity on thermal enhance heavy oil recovery. The following conclusion arising from this analysis can be drawn:

Well spacing plays an important role in thermal oil recovery factor. Although short distance between injector and producers leads to favourable RF, however, well space reduction is not a best way because well drilling costs and also early water breakthrough time in the producers.

Furthermore under the circumstances, increasing in well space may leads to recovery factor enhancement. This may happen, as a major issue, whenever the time injection period dramatically grows to convey the heat toward, around, the producers.

The influence of rate injection on the magnitude of recovery factor is more complex and depends on operational conditions of water injection and production. For injection rate greater than production rate may create some channelling due to quick water breakthrough. The favourable RF of high rate of both injection and production would have to be evaluated relative to possible undesirable effects induced short breakthrough time.

Studying the effect of injection temperature reveals that recovery will increase due to oil viscosity reduction. However viscosity reduction occurred around the injection well and it should be more interesting to how improve heat propagation throughout the heavy oil reservoirs.

Permeability and porosity heterogeneities in a heavy oil reservoirs considerably impact on enhanced oil recovery factor. Suggesting that characterization of heavy oil reservoirs is essential for evaluating thermal recovery factor in such reservoirs. Noted that regardless of the degree of reservoir heterogeneity, thermal recovery shows better performance to displace heavy oil by conventional waterflooding.

Results show that by 0.265 ratio of a geothermal doublet, enhanced oil recovery is observed approximately 12% . However this ratio can be reduced when the oil producers consider as another geothermal sources.

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