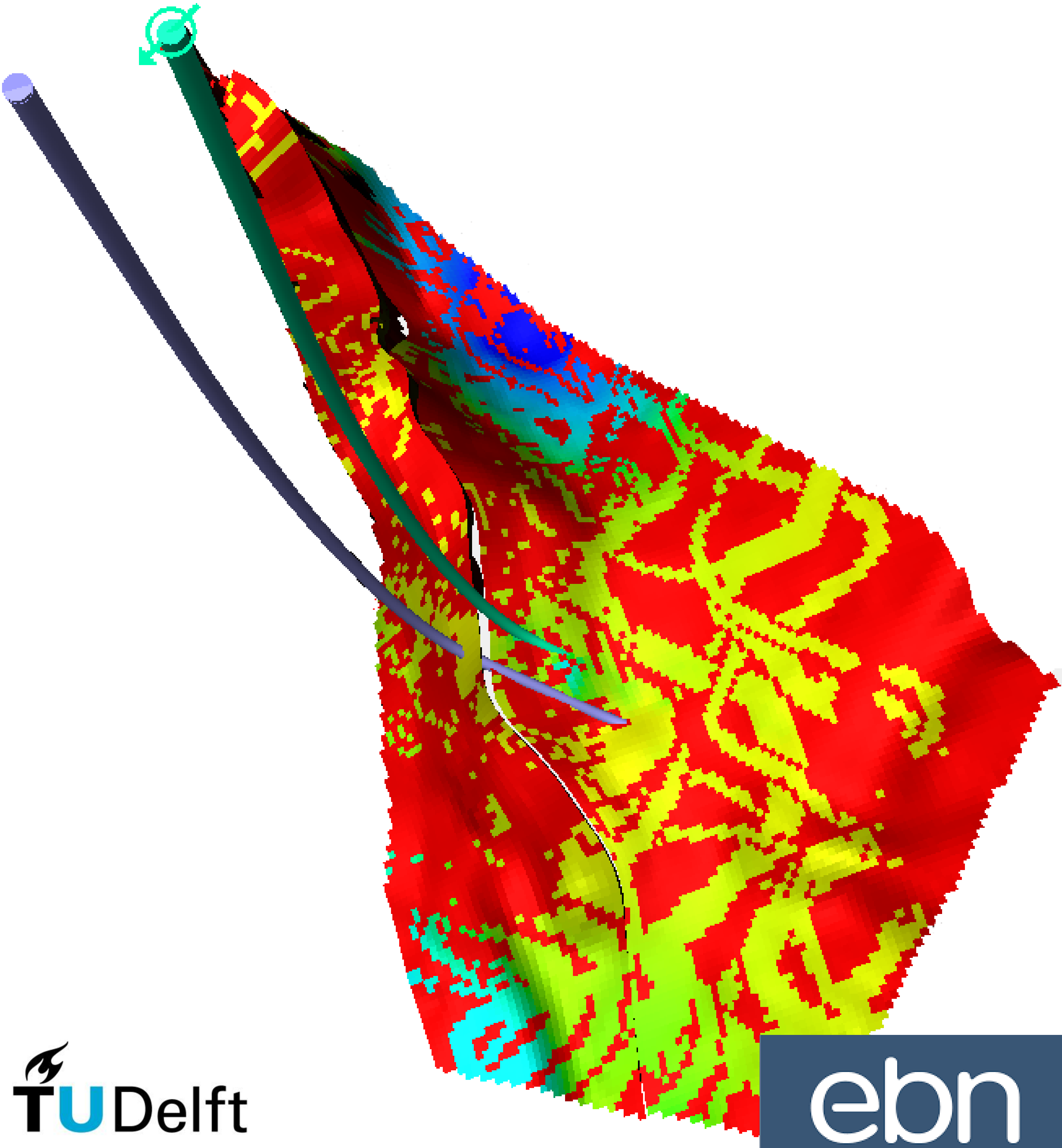
D. Aramburo

Synergy between geothermal and stranded oil fields to add value to geothermal projects



Synergy between geothermal and stranded oil fields to add value to geothermal projects

By

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Abstract

The Dutch Government is aiming for a CO_2 neutral energy supply in 2050; this requires a transition from using energy from fossil fuels to using renewable energy sources. Decline in oil production in the Netherlands occurs in an epoch with an increased interest in geothermal heat production as an alternative source of energy. In the present study it is investigated how oil production from stranded fields (fields abandoned when field development was considered not to be profitable), especially those with heavy oil, can add value to a geothermal project when thermally-enhanced oil recovery (EOR) with injection of hot water from a geothermal reservoir into an oil reservoir and coproduction of oil and geothermal energy is considered. The main focus is on the oil reservoir, while productivity and temperature of the geothermal source is assumed to be constant.

In order to determine the feasibility of such project, a geological model for an oil reservoir was constructed, taking the Moerkapelle field as a case study, so that reservoir simulations can be performed on it and results in terms of oil production, heat production, total energy production and economics can be obtained and analyzed. Geological modelling (structural and stratigraphic) and reservoir simulation are developed in three different *stages*, every time making the model more complex (*i.e.* heterogeneity due to structural and sedimentary features).

Project feasibility was calculated in terms of the percentage of reduction on the required subsidy for a geothermal project (required subsidy is the one that makes the NPV of a geothermal project to be zero under a pre-royalty pre-tax framework). For a homogeneous reservoir the reduction in required subsidy for a single doublet geothermal project can reach 85% and complete subsidy independence can be achieved when scaling up the project to 3 or more doublets. However, for heterogeneous reservoirs, the subsidy reduction for a single doublet geothermal project would not be higher than 52% in the most optimistic case and, when all the realizations are taken into account, there is no added value from the synergy but still an average reduction in the NPV of 13%. Scaling up the project to 3 or more doublets generates an average reduction of 31% in the required subsidy with a maximum reduction of 73% in the most optimistic case.

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1. Introduction

Production of oil and gas in the Netherlands is in a mature stage. Many hydrocarbon fields are reaching their end-of-field-life as production is decreasing to levels where it is no longer commercially or technically feasible; some others were previously abandoned when field development was considered not to be profitable after drilling of exploration wells (so-called stranded fields). This decline in production occurs in an epoch with an increased interest in geothermal energy production as an alternative source of energy in the Netherlands. Geothermal projects have been developed in the West Netherlands Basin (WNB), targeting the same reservoirs as the oil and gas wells in the area; aquifers are found between 1500 and 4000 meters depth with a temperature ranging from 50 °C to 120 °C.

The Rijswijk and Delft sandstone reservoirs of the Moerkapelle oil field were discovered in 1983 and were produced from 1985 to 1986. Production is characterized by high oil viscosity and low well productivity, operations were suspended in 1986 due to economic reasons. In 2009 the Delft University of Technology was granted an exploration and production license for geothermal energy in the WNB by the Dutch government. In the license area two geothermal doublets for greenhouse heating have been operating since 2010, producing water with a temperature of 70 °C from the Delft Sandstone Member (DSSM). The average water production rates from these two doublets are 105 and 140 sm^3/h with a standard deviation of 29 and 28 sm^3/h respectively (TNO, Aardwarmte productie en injectiedata, 2017). These big variability on water production rates is mainly related to operational issues, some of the projects have been out of operation during periods of up to six months.

The aim of the present study is to investigate how oil production from stranded fields, especially those with heavy oil, can add value to a geothermal project (*i.e.* how the synergy between geothermal energy production and stranded oil fields can make the geothermal projects less dependent on subsidies).

The study will be oriented on the potential synergy of thermally-enhanced oil recovery (EOR) with injection of hot water from a geothermal reservoir into an oil reservoir and coproduction of oil and geothermal energy (oil coming from the oil reservoir and geothermal energy generated from hot fluids produced from both, the geothermal and the oil reservoir). The main focus of this project is on the oil reservoir, while productivity and temperature of the geothermal source was assumed to be constant.

For such purpose, a geological model for an oil reservoir (the Moerkapelle field was selected as a case study) was constructed in different stages in order to perform reservoir simulations. With the proposed methodology, results in terms of oil production, heat production, total energy production and economics can be obtained directly and indirectly from the simulations developed in the reservoir model. Sensitivity analysis on parameters as rock compressibility and injection temperature have been performed in the constructed reservoir model. Parameters influencing the decrease in oil production when introducing geological complexity to the model have been found and analyzed.

Ventures like the proposed synergy, where two different projects that use different equipment (and have some infrastructure in common) are merged, do not exist in the Netherlands until the date. The geothermal and the hydrocarbon projects are taxed in a different way; geothermal projects are considered to contribute as an innovative low carbon-emission technology, reason why they are subsidized by some entities in order to promote the growing of green energy in the country. On the other hand, for oil projects, taxes are applied to the income and royalties are applied to the produced oil.

It is not known how a project as the synergy between geothermal and stranded oil fields would be taxed by the authorities; as well as how is going to be decided which equipment belongs to each side of the project (this is necessary for example to decide whether depreciation of certain equipment is subtracted from the calculation of the taxes of one project or the other). Due to the difficulty to perform an economic analysis including royalty and taxes under different tax and subsidy regimes, the economic analysis was developed under a pre-royalty-pre-tax framework.

Project feasibility was calculated in terms of the percentage of reduction on the required subsidy to make the synergy economically neutral (NPV=0). This is calculated as the percentage of change between the Net Present Value (NPV) of the synergy project and the NPV of a stand-alone geothermal project with the same production rate and temperature as that considered in the synergy project.

2. Geological Background

The Jurassic and Cretaceous reservoirs in the Moerkapelle oil field consist of an elongated NW-SE trending, heavily faulted asymmetrical "*flower*" structure. The horst is formed by two steeply dipping normal faults at Triassic level which diverge upwards into several normal and reverse faults at Upper Jurassic-Lower Cretaceous reservoir level. The major feature, is the Moerkapelle Boundary Fault, a NW-SE trending sealing fault (NAM, 1995).

2.1. Location - Regional Geology

The Moerkapelle Field is situated on top of the WNB, which is well known for the abundance of oil and gas fields in complex geological structures and, most recently, for the increased interest in the geothermal operations in the area. The WNB is situated on top of a tectonically active area where deformation has been relevant from the Late Carboniferous (Gilding, 2010).

Fig. 1 illustrates the Location of the Moerkapelle field within the WNB. It is noticeable that the Moerkapelle field is located exactly in the same area as one main geothermal exploration license (Zuidplats geothermal exploration area). On the other hand there are several operating geothermal fields (production licenses) located as close as 10 km to the Moerkapelle field.

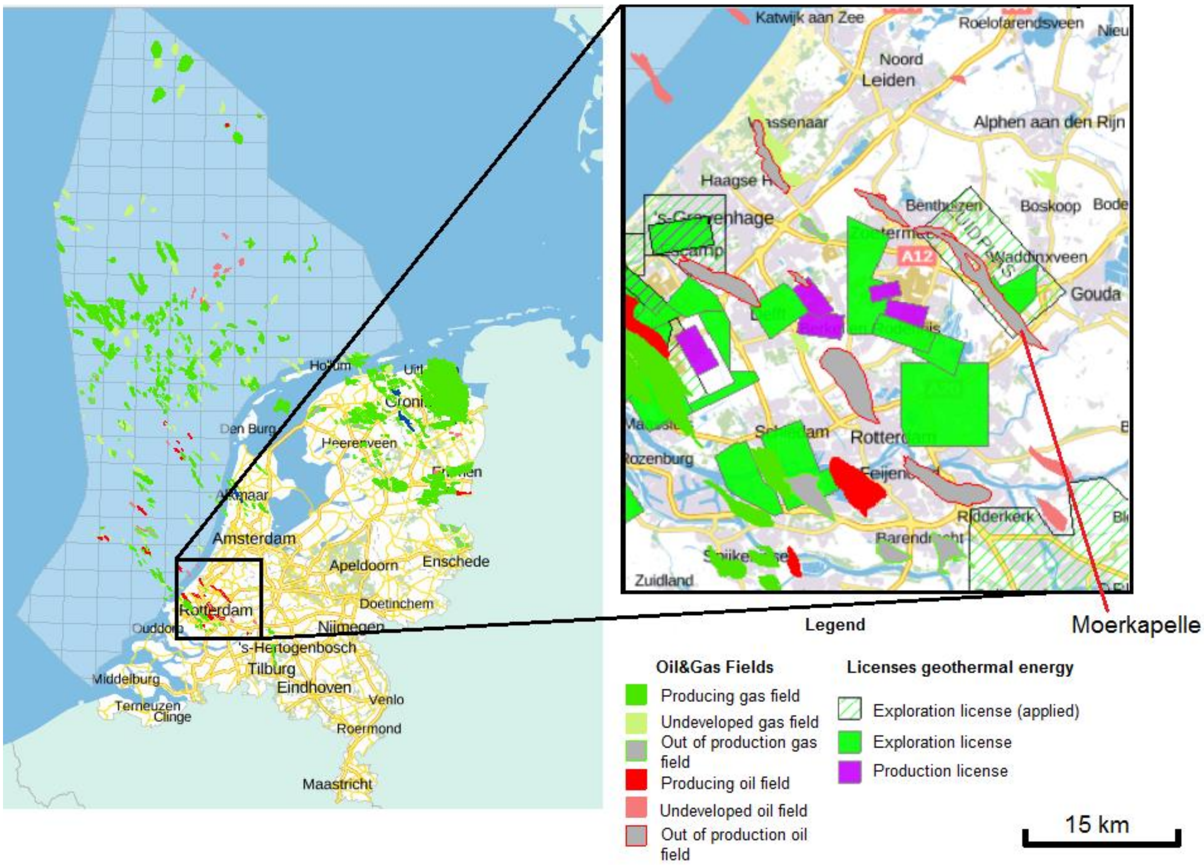


Fig. 1. (Left) Map of the Netherlands oil and gas fields. (Right) Location of the Moerkapelle field within the WNB (Modified after TNO, 2016)

2.2. Stratigraphy

Fig. 2 presents the stratigraphic column of the WNB in the study area highlighting the stratigraphic position of the main reservoirs of the Moerkapelle Field, the Delft Sandstone Member (DSSM) and the Rijswijk Member (KNNSR). The DSSM is part of the Nieuwerkerk Formation (belongs to the Schieland Group) and consists of a fluvial succession formed during and after a major Early Cretaceous rifting phase (Donselaar *et al.*, 2015). The Nieuwerkerk Formation consists, from base to top, of the Alblasserdam Member, the DSSM, and the Rodenrijs Claystone Member. The KNNSR is part of the Rijnland Group; conformably overlies the Rodenrijs Claystone Member as a gradual transition from claystone to a large thick sandstone body (van Adrichem Boogaert and Kouwe, 1993).

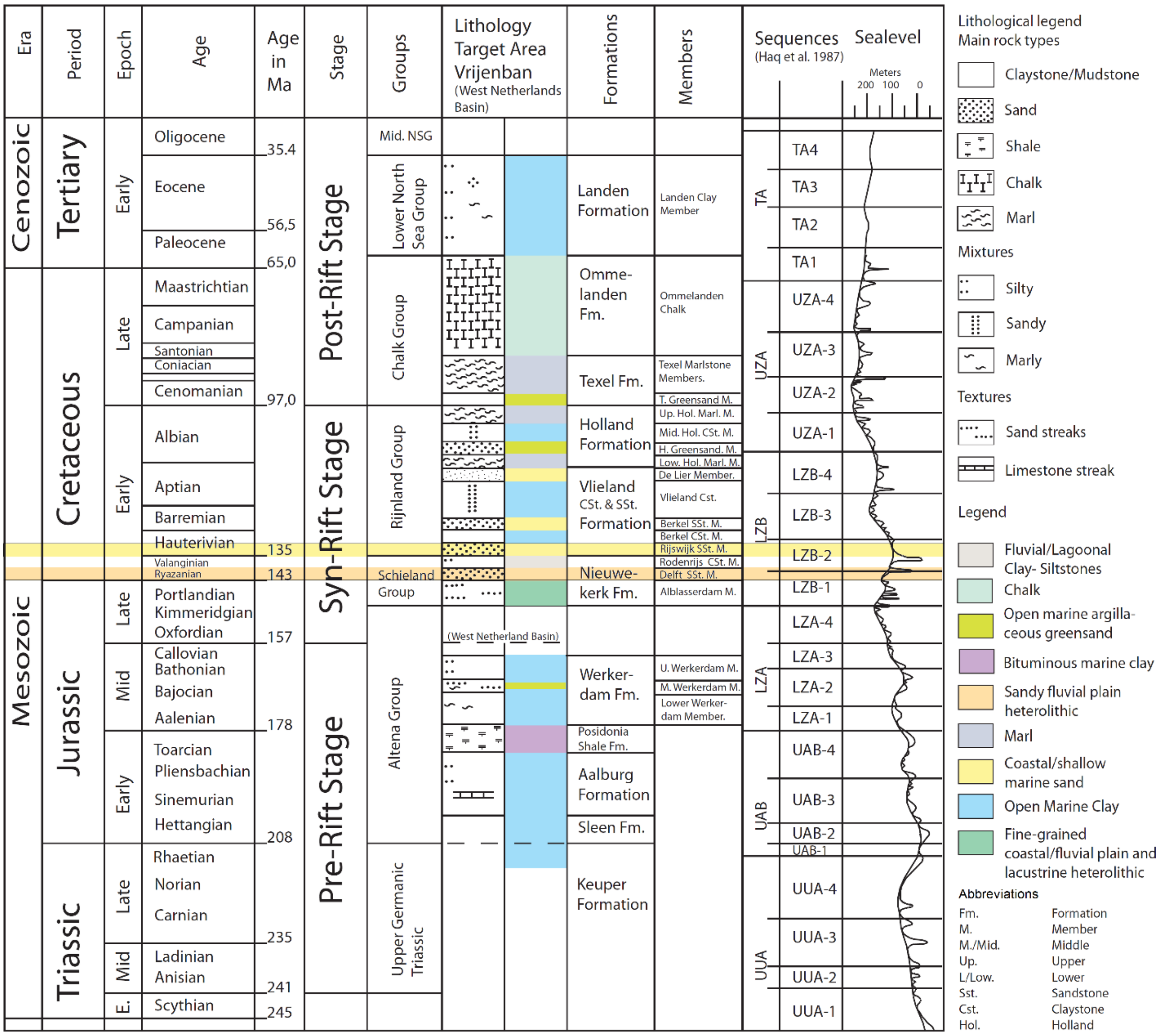


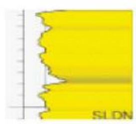
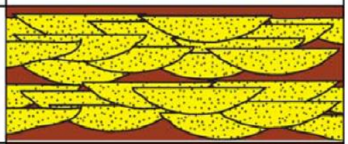
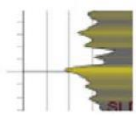
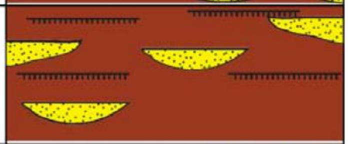
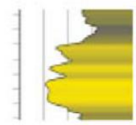
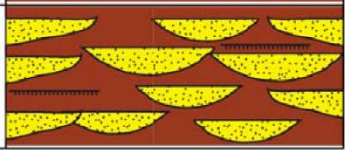
Fig. 2. Stratigraphy of the area. Lithology based on wells DEL-3, DEL-8, PNA-13, PNA-15 and RWK-1 (After Gilding, 2010). Stratigraphic nomenclature based on van Adrichem Boogaert and Kouwe (1993). Sequences and eustatic sea level curve after Haq *et al.* (1988). Colored Line: Stratigraphic position DSSM (dark yellow) and the KNNSR (light yellow).

2.2.1. Delft Sandstone Member (DSSM-*SLDND*)

The DSSM is not always found in the wells of the Moerkapelle Field. It is formed by a fine to coarse-gravelly, light-grey massive sandstone succession with abundant lignitic matter (Donselaar *et al*., 2015). Multiple and single stacked fining upward sandstone bodies contain very coarse to large, even gravel size grains, clayclasts and lignite particles at the base (Gilding, 2010). The member is interpreted as a fluvial meandering system or stacked distributary channel deposit in a lower coastal plain setting (van Adrichem Boogaert and Kouwe, 1993). The thickness ranges from 60 m up to 115 m (Gilding, 2010).

The DSSM was subdivided into three different units by Gilding (2010) based on the characteristic signature on well logs and cores. The three subunits of Delft Sandstone Member can be explained by differences in the rate of subsidence and the characteristic effect of the development of the fluvial system related to the created accommodation space (depositional architecture). **Table 1** gives a description of the facies encountered in each subunit and their characteristic reservoir architecture.

Table 1. Gamma-ray log signature, facies description and interpreted depositional architecture of the three units in the Delft Sandstone Member. After Gilding (2010)

Unit	Gamma-ray signature	Facies description	Depositional architecture
Delft Sandstone Member Upper Unit		Multiple-stacked and laterally-amalgamated fluvial channel sand-stone bodies	
Delft Sandstone Member Middle Unit		Interbedded claystone and siltstone deposits with coal layers. Floodplain.	
Delft Sandstone Member Lower Unit		Single fining-upward meandering river sandstone bodies interbedded with claystone and siltstone flood-plain deposits.	

2.2.2. Rodenrijs Claystone Member (SLDNR)

Consists of grey lignitic claystone, siltstone and sandstone, characterized by laminated or contorted bedding and lignite/coal beds with well-preserved plant fossils (Van Adrichem Boogaert and Kouwe, 1993). Lower-coastal-plain to lagoonal depositional environment is inferred by Donselaar et al. (2015).

2.2.3. Rijswijk Sandstone Member (KNNSR)

Consists of light to medium-grey sandstones with a very fine to medium and grain size (locally gravelly). Mica, lignitic matter and siderite concretions are common. Locally, lignitic claystone beds are present, especially near the base. The deposition environment is inferred to be shallow marine; the majority of the sands in this member have been deposited as basal transgressive sands, which were intensely reworked by bioturbation, waves and storms (van Adrichem Boogaert and Kouwe, 1993). The top of the KNNSR is found in the Moerkapelle Field at a depth of approximately 830 m true vertical deep sub-sea (TVDSS). Thickness goes up to 22 m.

2.3. Structural Geology

Fig. 3 illustrates the great differences in thickness in the members of the Nieuwerkerk Formation, that are thought to be due to differential subsidence in a synsedimentary horst-graben structure. The Moerkapelle Field area (located in the Pijnacker High in **Fig. 3**) behaved as a horst during the deposition of the main reservoir rocks. For this reason the thickness of the reservoir in this area is expected to be smaller than the thicker successions found in the Vrijenban Syncline to the SW.

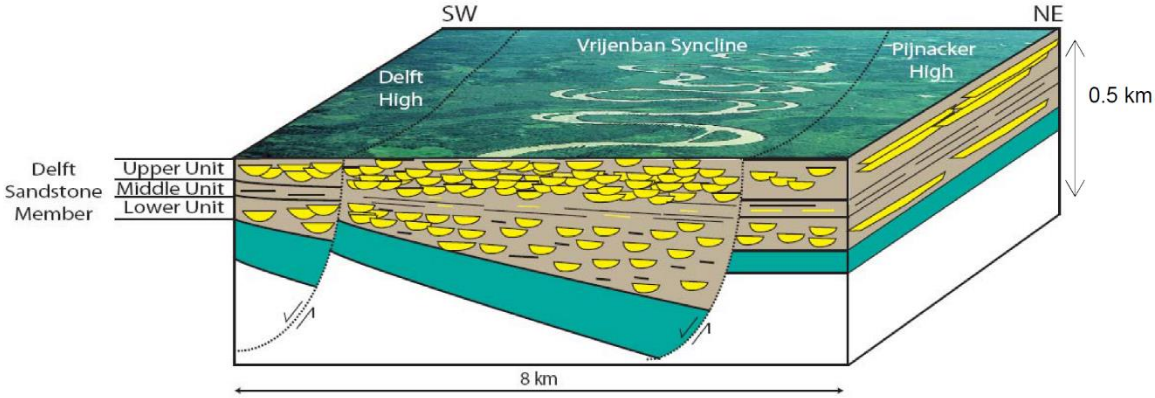


Fig. 3. Depositional model for the DSSM in the study area. After Gilding (2010)

Compressive forces in the WNB caused inversion of the structures during the Santonian to Campanian interval (Gilding, 2010). Typical for these structural styles are reverse faults and the strike-slip faults along the pre–existing faults, creating “*flower*” structures as those shown in **Fig. 4**. In these structures most of the oil and gas reservoirs in the WNB are found.

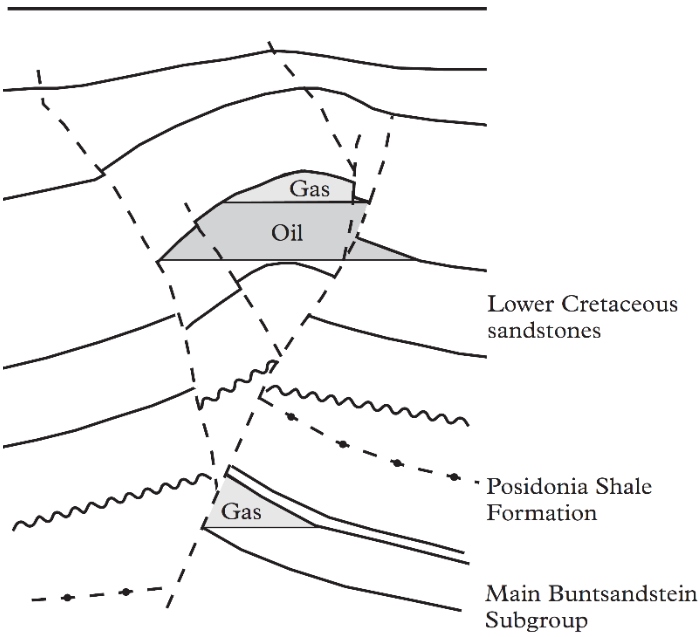


Fig. 4. **Characteristic trap situation in the WNB**. After van Balen *et al.* (2000)

2.4. Reservoir Properties

The average net-to-gross of the reservoir (DSSM, SLDNR & KNNSR) is around 0.4. Porosity ranges from 16% to 25%. Well test permeabilities range from 900 - 5000 mD. The average oil saturation in the reservoir is 74%. The oil is heavy at 15º API and viscous at 850 cP in-situ. The Oil-water contact (OWC) is at 850 m TVDSS south-west of the Moerkapelle boundary fault. To the north-east, the OWC is at 900 m TVDSS (NAM, 1995).

In order to take into account geological complexities as those caused by channels, only the DSSM was considered to be developed in the synergy project. This also make sense since most of the oil in the reservoir is contained in the DSSM (17.8 MMsm^3 compared to 1.1 MMsm^3 in the KNNSR).

2.5. Geothermal projects in the study area

An inventory of production from existing geothermal doublets in the area was carried out in order to determine the capacity of the geothermal reservoir below the Moerkapelle field to provide water to be used for injection in the heavy oil reservoir. **Table 2** summarizes the mean and standard deviation (SD) on the production and injection rates for the geothermal installations located in the study area. The big variability on water production rates is mainly related to operational issues, some of the projects have been out of operation during periods of up to six months.

Table 2. Inventory of production from existing geothermal doublets in the study area. Installations listed by distance to the Moerkapelle field (nearest at the top)

	Production (sm^3/hour)		Injection (sm^3/hour)	
Installation	Mean	SD	Mean	SD
Pijnacker-Nootdorp Geothermie	105	29	105	29
Pijnacker-Nootdorp Zuid Geothermie	140	28	140	28
De Lier Geothermie	259	40	259	40
Honselersdijk Geothermie	101	62	127	38
Installatie Berkel en Rodenrijs	140	21	140	21
Installatie Bleiswijk	181	19	181	19
Vierpolders Geothermie	102	74	84	88

3. Methodology

The main focus of the work in this thesis is on the oil reservoir, while productivity and temperature of the geothermal source was assumed to be constant based on the data on **Table 2**. The development of the project involves two main processes: geological modelling (structural and stratigraphic) and reservoir simulation. Those two processes are repeated in three different *stages*, every time making the model more complex; *i.e.* heterogeneity due to structural and sedimentary features. The main processes in this cyclic loop are illustrated in **Fig. 5**.

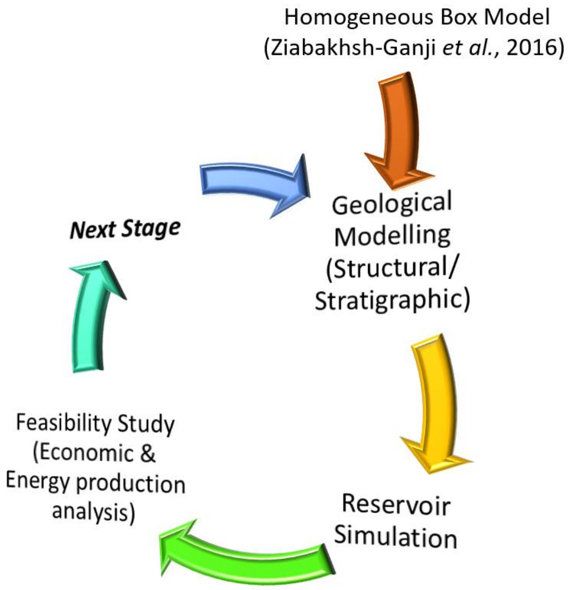


Fig. 5. Flowchart illustrating the methodology used during the project. The starting point is an homogeneous box model constructed by Ziabakhsh-Ganji *et al*. (2016)

In the following section a description of the methodology used for each *stage* is given. All the geological modelling processes were developed in PETREL E&P Software Platform (2015) while the reservoir simulation were performed in ECLIPSE Industry Reference Reservoir Simulator, using keywords as input; PETREL was used as a grid/properties keyword generator and as a result visualization software. **Fig. 6** summarizes the main characteristics of the three stages in which the project was developed.

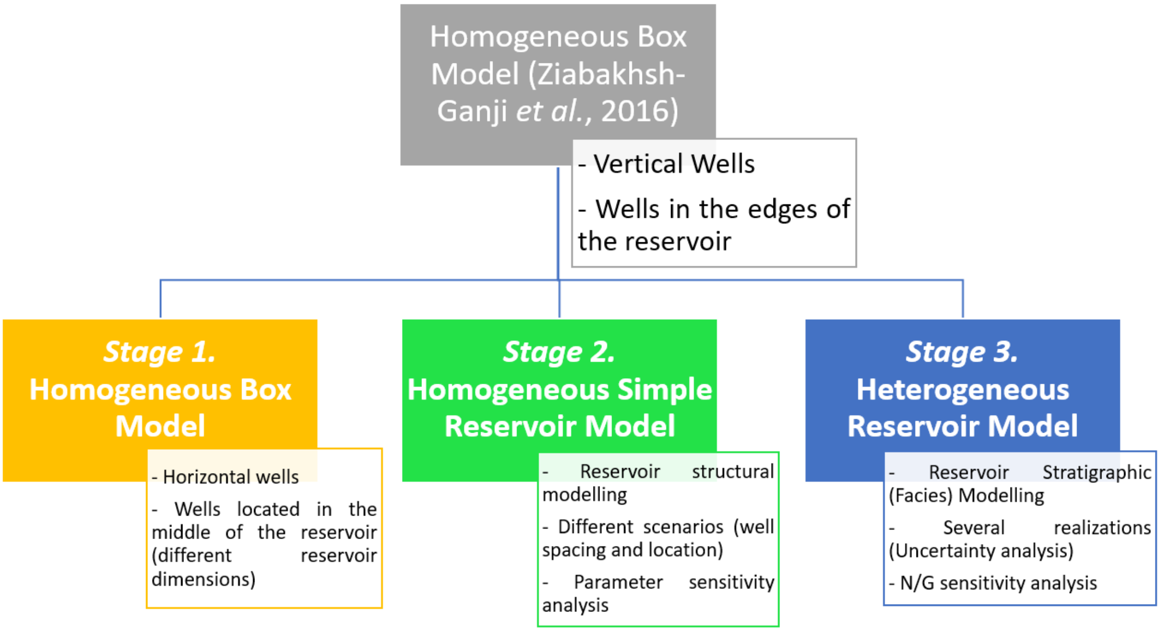


Fig. 6. Three main stages resulting from the process illustrated in Fig. 5

3.1. Stage 1*. Homogeneous Box Model*

Ziabakhsh-Ganji *et al.* (2016) developed a homogeneus box reservoir model with the rock and fluid properties assumed for the Moerkapelle Field (some of them not known first-hand) and two vertical wells for injection and production. The dimensions of the model, however, were set for optimizing recovery factor (RF) and not final production. In order to account for project feasibility issues (economics), the model from Ziabakhsh-Ganji *et al.* (2016) was modified so that the production of oil is maximized. A more detailed explanation on the modifications to the model is mentioned in the following section.

3.1.1. **Geological Modelling (Structural)**

There are no significant changes in the structural model used in *Stage 1* compared to that presented by Ziabakhsh-Ganji *et al.* (2016). We modified some parameters as the reservoir dimensions (see **Table 3**) in order to maximize production, horizontal wells were added and different well spacings were considered. Rock and fluid properties used in this stage are the same as those used by ZiabakhshGanji *et al.* (2016).

3.1.2. **Reservoir Simulation**

In this section we created several different scenarios with 100000 cells (100x100x10) of different dimensions (see **Table 3**) in order to consider different factors such as water injection constraints. **Table 3** gives a description of all the scenarios considered; all the values in the simulation are in field units since it was taken from the original reservoir model (Ziabakhsh-Ganji *et al.,* 2016).

Some of the boundary conditions applied during a 30 years simulation for all the scenarios are: a water injection constraint (BHP) of 2500 psia (~172 bar, assumed value in absence of leak off tests for the formation). Production constraint (BHP) of 75 psia (~ 5.2 bar) and maximum liquid rate of 22000 STB/d (~3600 m^3/d). Horizontal wells of 3248 ft (~990 m) horizontal section through the middle height of the reservoir. Injection temperature is considered to be 100 °C, sensitivity analysis on the effect of injection temperature was conducted and there is not a significant difference between 70 and 100 °C, more detailed results on the sensitivity can be found on **Appendix F.7**.

Table 3. Characteristics of different scenarios for the homogeneous box model

Scenario	Description
A	Model dimensions: 9800 ft x 9800 ft x 98 ft ~3000 m x 3000 m x 30 m Well Spacing: 1673 ft ~ 500 m (in the center of the reservoir) Water injection constraint: Rate 2200 STB/d ~15 sm^3/h
B	Model dimensions: Adjusted to be close to known reservoir width 9800 ft x 4593 ft x 30 ft ~ 3000 m x 1400 m x 9 m Well Spacing: 1673 ft ~ 500 m (in the center of the reservoir) Water injection constraint: Rate 10000 STB/d ~68 sm^3/h
C	Model dimensions: 9800 ft x 4593 ft x 30 ft ~3000 m x 1400 m x 9 m Well Spacing: Reduced to improve thermal sweep, 787 ft ~ 240 m (in the center of the reservoir) Water injection constraint: Adjusted to half the expected water rate from geothermal well; 10000 STB/d ~68 sm^3/h
D	Water injection constraint: Adjusted to expected water rate from geothermal well; 20000 STB/d ~132 sm^3/h ~3180 sm^3/d/well Same parameters as C, considers the performance of a single doublet in presence of more wells (3 injectors and 3 producers in the field).
D_Cold	Same as D. The water injection is done at reservoir temperature; developed to compare the performance of D against a conventional water injection secondary recovery.

Examples of the configuration of the wells and the reservoir dimensions for scenarios B and D can be found in **Appendix A**.

3.2. Stage 2. *Homogeneous Simple Reservoir Model*

Stage 1 considered the reservoir as a box with a continuous and homogeneous sandstone; however, oil reservoirs are characterized for their structures, that often are complex and differ very much in behavior from a simple box. In order to take into account this complexity, a structural model was built for the Moerkapelle field, as a case study. Details on the construction of the geological model (structural), reservoir simulations performed on it, and its economic and energy production analysis are covered in this section.

3.2.1. **Geological Modelling (Structural)**

Construction of a geological model for the Moerkapelle oil field is one of the main goals of the present study. Terracube 3D and the L3NAM1985 seismic cube (available on nlog.nl) was used for constructing a geological model that takes into account the reservoir geometry; an example of a cross section in time from the Terracube is illustrated in **Appendix B**. The seismic coverage is very good, while the resolution is poor; especially in the reservoir area. This makes the interpretation of small intra-reservoir faults and other features troublesome.

Several surfaces have been regionally interpreted by TNO (2014) for the whole Netherlands, one of them the top of the Schieland Group. In absence of check shot data that allow to develop the well to seismic match through a syntethic seismogram, the top Schieland Group surface was used as a guide for interpreting one of the reservoir horizons, since it corresponds with the top of the Rodenrijs Claystone Member in the area (See **Fig. 2**). The most continuous body reported during drilling within the field is the KNNSR, as can be seen in the well section presented in **Appendix C.** For this reason the member was interpreted as the Hard Kick just above the top Schieland Group in a more detailed manner (reservoir scale), as shown in **Appendix D**.

From the horizon created by the seismic interpretation of the KNNSR and the modelling of the boundary faults, a structural model from isochore maps was built. Isochore maps were built interpolating the thickness of each reservoir zone from the reported and interpreted well tops. With these isochore maps and the well tops themselves the additional reservoir zones were added to the existing KNNSR. **Fig. 7** illustrates the reservoir model generated for three zones (KNNSR, SLDNR and DSSM).

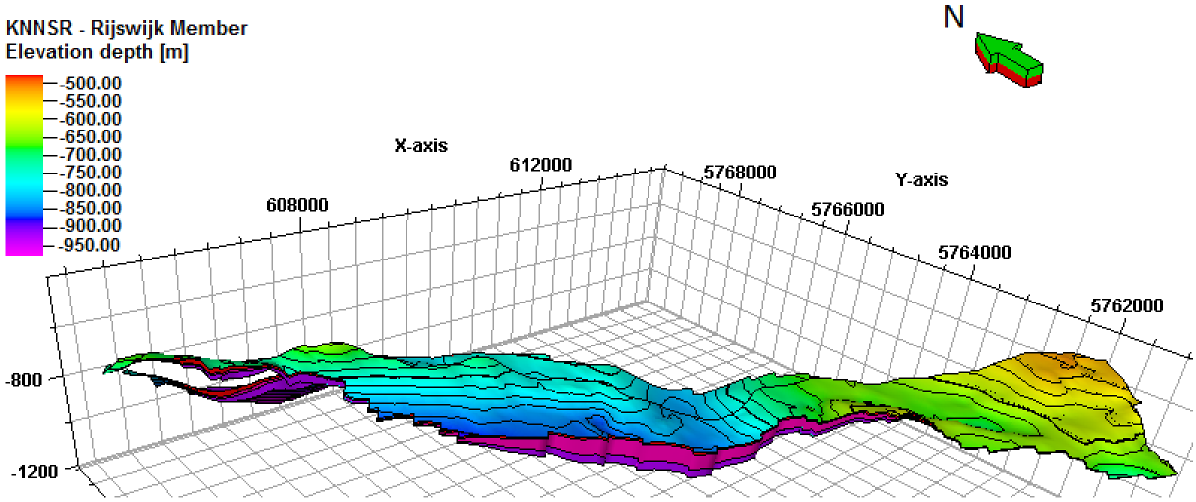


Fig. 7. Homogeneous Simple Reservoir Model for 3 zones. All values in meters

3.2.2. Reservoir Simulation

In *Stage 2* the reservoir simulation was done in two different steps. The *First Step* (comparable) is meant to be a reasonable comparison (*i.e.*, using exactly the same parameters) with *Stage 1* (scenario C) while the *Second Step* more closely represents the properties of the Moerkapelle reservoir reported by NAM (1995). The water injection rate limit for *Stage 2* was set to be the maximum expected water rate from the geothermal well (150 sm^3/h).

In the *Second Step* homogeneous rock properties were assigned to the three zones using average reported values by NAM (1995). **Table 4** summarizes the average values used for property modelling in the homogeneous simple reservoir model. Some other properties, not available at this stage for the Moerkapelle field, were kept the same as in Ziabakhsh-Ganji *et al.* (2016). A water injection constraint (BHP) of 1500 psia (~103 bar) was assumed for the *Second Step* in absence of leak off tests for the formation (it is ~10% higher than reservoir pressure).

Table 4. Parameters used for filling grid properties on Stages 1 and 2

Property (units)	*Stage 1*	*Stage 2*		
		KNNSR	SLDNR	DSSM
Porosity (%)	18	21	0	21
Net/Gross (%)	100	67	0	40
Water Saturation (%)	17	17	100	26
Permeability x,y,z (mD)	495	1500	0	1000

In order to take into account geological complexities as those caused by channels, only the DSSM was considered to be developed in the synergy project. This also make sense since most of the oil in the reservoir is contained in the DSSM (17.8 MMsm^3 compared to 1.1 MMsm^3 in the KNNSR).

Three different scenarios were developed to analyse the potential in different areas of the reservoir for the synergy with geothermal production. A map with the location of the doublet (injector-producer) for each of the three scenarios can be found in **Fig. 8** while their well and reservoir geometry characteristics are summarized in **Table 5**. In **Fig. 8** can be observed that the Northeastern block of the reservoir was used in Scenarios F and G; this block has never been explored except for one well in the Northwest that confirmed an OWC for that side of the fault. Despite the fact of the uncertainty on the presence of hydrocarbons on the Northeastern block, it was assumed as oil-bearing and used during this project as an area that allows to investigate the performance of extended reach horizontal wells in the synergy project.

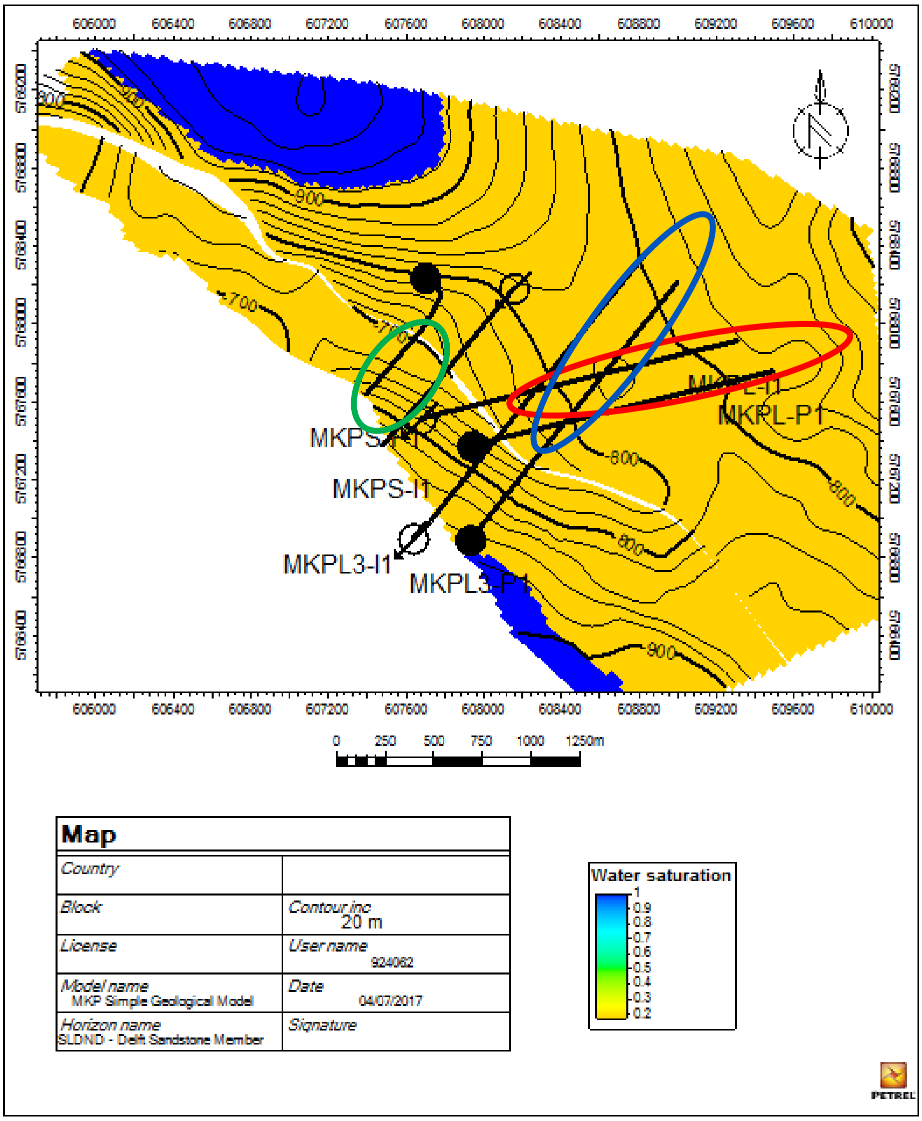


Fig. 8. Scenarios in *Stage 2* on a contour map for the top of DSSM (SLNDND). Colors in the map represent water saturation (oil saturation is yellow). Three groups of wells (doublets) with different orientations are illustrated by black continuous lines and their areas of influence are circled in different colors; those correspond to the three production scenarios summarized in Table 5 (Green: Scenario E, Red: Scenario F, Blue: Scenario G)

Table 5. Well and reservoir geometry characteristics for the different scenarios used in *Stage 2*

Scenario	Average Well Horizontal Section (m)	Average Well Spacing (m)	Penetrated Reservoir Average Thickness (m)	Name of wells (Fig. 8)
E	380	250	20	MKPS
F	1000	250	23	MKPL
G	1000	250	10	MKPL3

3.2.3. Economic Analysis

The economic analysis was developed under a pre-royalty-pre-tax framework at this stage of the project; the main reasons for this decision are legal. As there are no similar projects in the Netherlands it is not known how they would be taxed by the authorities; as well as how is going to be decided which equipment belongs to each side of the project (Geothermal-EOR for heavy oil). The oil price used is 50 USD/STB (~45.5 Euro/STB), heat price 0.012 Eur/kWh (ECN, 2017) and the discount rate is 8%.

Geothermal projects, as other renewable energy projects, are not economically attractive under a business as usual situation at the current state of development; for this reason subsidies are provided by energy and environmental authorities in order to increase the interest in such projects. The main assumption in this economic analysis is that the synergy between a geothermal and an EOR project would make the first subsidy-independent, therefore subsidies where not taken into account despite the fact that they could be received (making the project more interesting from an investor point of view).

We calculated the Net Present Value (NPV) for the geothermal and EOR sides of the project and then added them up to obtain the NPV of the synergy. Different methods of calculating the costs were used for the two parts of the project; their main characteristics and implications are shown in the following section.

The Investment and Operational costs (CAPEX and OPEX) and the price of the heat used in the *Economics of the Geothermal Project* were based on a price per kilowatt (kW) output of heat as reported by ECN (2017). **Table 6** compiles the information regarding the calculation of the NPV for the geothermal project only.

Table 6. Variables used in the NPV calculation of the Geothermal side of the synergy. After ECN (2017). CAPEX and fixed OPEX are calculated with the capacity of the instalations, while variable OPEX is calculated with the actual output of the system

Item	Value	Units
Investment Costs (CAPEX)	€ 1,622	Euro/kW (capacity)
Fixed OPEX	€ 59	Euro/kW/year (capacity)
Variable OPEX	€ 0.008	Euro/kWh/year (output)

For the EOR project, on the other hand, CAPEX was obtained by importing the oil and water production profiles into QUE$TOR ®; while OPEX was calculated using typical factors used by EBN for oil onshore projects. **Table 7** summarizes the values used for the calculation of the NPV for the EOR project.

Table 7. CAPEX and OPEX for the EOR side of the synergy

Item	Value	Units
CAPEX		
Production Facility	€ 12,744,545	Euro
Pipeline to Rotterdam	€ 6,840,000	Euro
OPEX		
Fixed OPEX	3%	of cumulative CAPEX/year
Variable OPEX	11.45	Euro/sm3 (oil)
Oil Evacuation costs	11.45	Euro/sm3 (oil)

3.2.4. Heat Production

The heat production is assumed to occur through the transfer of heat from the produced fluids (oil and water) to a heating fluid (probably water) in a heat exchanger on the surface. The amount of heat produced in such equipment is calculated by the general equation of conductive heat transfer shown in **Eq. 1.** The fluid parameters used for heat production calculation are compiled in **Table 8**. Heat produced on the heat exchangers is mainly coming from commingled oil and water production in the producer well and warm water production in the geothermal well. Water produced in the geothermal well correspond to volumes that is not injected to the oil reservoir due to pressure constraints.

$$Q = \rho V C_p \Delta T * \left(\frac{1\ kWh}{3600000\ J}\right)$$

Eq. 1. Produced heat from production fluids in the heat exchanger in a time interval. Q: Heat, ρ: Production fluid density (Oil-Water), V: Volume of fluids produced in the time interval, C_p: Fluid specific heat, ΔT: Change of temperature of the fluids in the heat exchanger (production-injection).

Table 8. Fluid parameters used for heat production calculation

Parameter	Value	Units
Cp water	4219	J/kgK
ρ water	958	kg/m3
Production Temperature	100	°C
Injection Temperature	40	°C
Cp oil	2093.4	J/kgK
ρ oil	972	kg/m3

3.2.5. Total Energy Production

Economic indicators are not the only criteria to decide whether a project is attractive, especially when parameters as interest rates, oil and heat price are subject to sudden change and dependent on many other factors. From an enthalpy point of view, the project is always interesting whenever the amount of energy obtained is bigger than the energy invested on it (*e.g.* the amount of energy produced in the synergy is bigger than that would be obtained from a stand-alone geothermal project without any oil production).

Consequently, the total energy production was calculated by applying a multiplier to the oil production (the approximate heat content of crude oil, 1628.2 kWh/BBLoeq) and summing up the energy obtained from the oil to the heat obtained from the geothermal side of the project.

3.3. Stage 3. Heterogeneous Reservoir Model

Stage 2 considered a continuous and homogeneous sandstone as the oil reservoir; however, fluvial sandstones (as the SLDND) are characterized for their discontinuity and heterogeneity. In order to take into account this complexity, a facies model was developed on the existing structural model for the Moerkapelle reservoir (from *Stage 2*). Details on the construction of the geological model, the reservoir simulations performed on it, and its economic and energy production analysis are covered in the following section.

3.3.1. Geological Modelling (Stratigraphic)

3.3.1.1. Facies Modelling

In order to construct a heterogeneous reservoir model, six different facies (see legend on **Fig. 9**) were identified on the well logs with the gamma ray as an indicator and making use of known stratigraphy and the sedimentary environment of the three zones modeled (KNNSR, SLDNR and SLDND).

Uncertainty on the location of each of the facies within the reservoir was accounted for by the development of 50 different realizations; we used object modelling (stochastic) in the facies modelling core on PETREL® 2015 with the facies percentages obtained from well logs and varying the seed. The seed defines the start of the random number generation in the property-population algorithms (using the same seed number produces the same model); different realizations have different positions of the channels within the reservoir (all of them being equally probable).

Fig. 9 illustrates the results of the facies modelling for four different layers within the reservoir. Channel thickness in the SLDND varies from 1.5 to 4.5 meter with an average of 3 meters as reported by Loerakker (2009). The width of the channels was derived by Gilding (2010); it varies from 12 meter to 195 meters with an average of 92 meters. As no data are available on the sinuosity of the channels this is set using the default settings of Petrel; a wave length of 1500 meters and amplitude of 800 meters with a drift of 0.2. The flow direction reported by van Adrichem Boogaert & Kouwe (1993) is similar to the axis of the West Netherlands Basin (Southeast to Northwest). The average flow direction for all the realizations is 315 degrees with a normal spread of 5% or 15 degrees as in Gilding (2010). A base case realization was defined using a seed of 29258 (preset from Petrel).

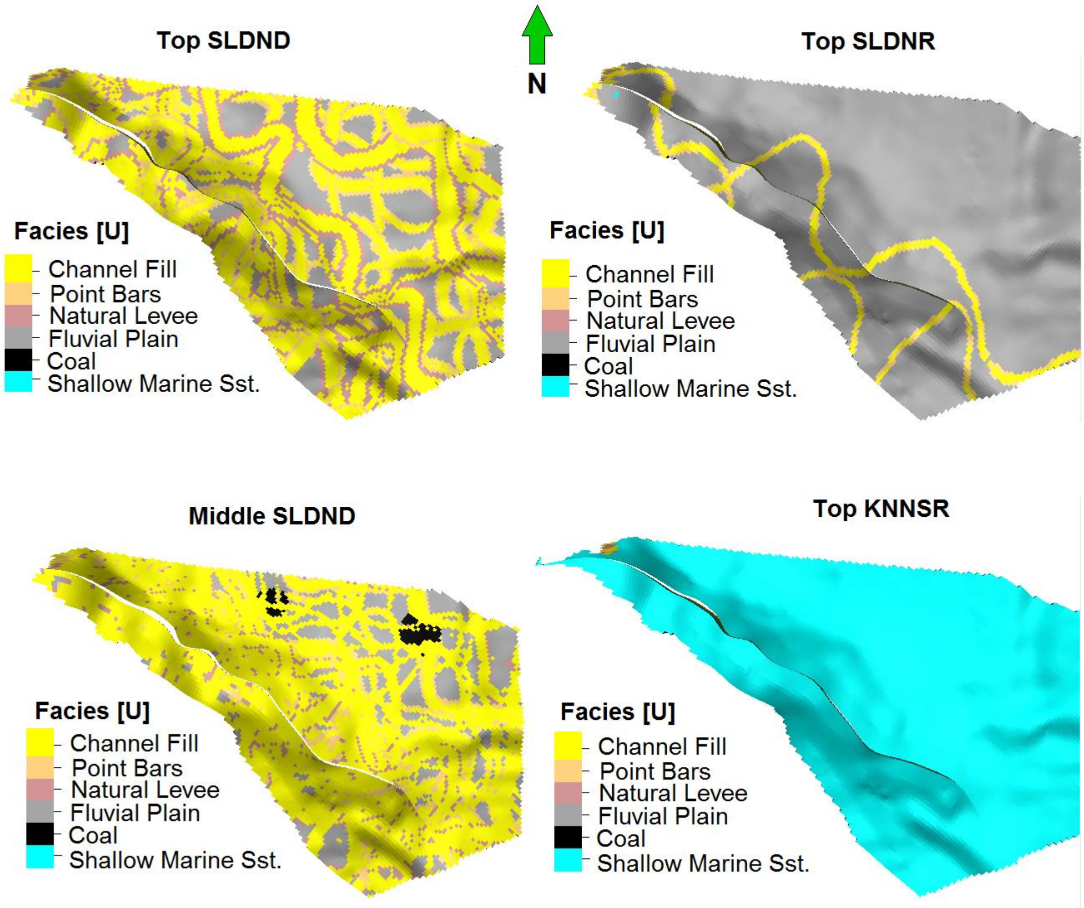


Fig. 9. Facies modelling for 4 different layers within the reservoir (Base case realization)

3.3.1.2. Petrophysical Modelling

The porosity was modelled in Interactive Petrophysics (IP) wellbore software platform; it was calculated from density, sonic and neutron well logs in six wells with enough information from the Moerkapelle Field (MKP-9, MKP-9-S1, MKP-10, MKP-12-S1, MKP-14 and MKP-15). For some of those mentioned wells even a calculated effective porosity log from NUTECH (2013) was available. **Table 9** summarizes the parameters used for the calculation of porosity. The clay volume (V_{cl}) was obtained from single clay indicator (Gamma Ray) and double clay indicators (Density-Neutron & Density-Sonic) and an average between those two was calculated. **Fig. 10** is an example of the logs of the calculated porosity and clay volume for the well MKP-10.

Despite the fact that resistivity logs were available in a few wells, water saturation was not calculated but instead the same constant values as the homogeneous model were used (see **Table 4**). The main reason for this was the lack of information on water salinity to perform calculations and the unrelevance of the calculation itself, since development area for the synergy is on the opposite block from the location of the Moerkapelle wells (see **Fig. 14**).

Table 9. Parameters used for calculation of porosity

Density Porosity		Sonic Porosity	
Correlation used	$\phi_{den} = \dfrac{\rho_{matrix} - \rho_{log}}{\rho_{matrix} - \rho_{fluid}}$	Correlation Used	Wyllie: $\phi_s = \dfrac{\Delta t_{log} - \Delta t_{matrix}}{\Delta t_{fluid} - \Delta t_{matrix}}$
Matrix density (g/cm^3)	2.65	Matrix Slowness (µs/ft)	55.5
Fluid density (g/cm^3)	1.00	Fluid Slowness (µs/ft)	189.0

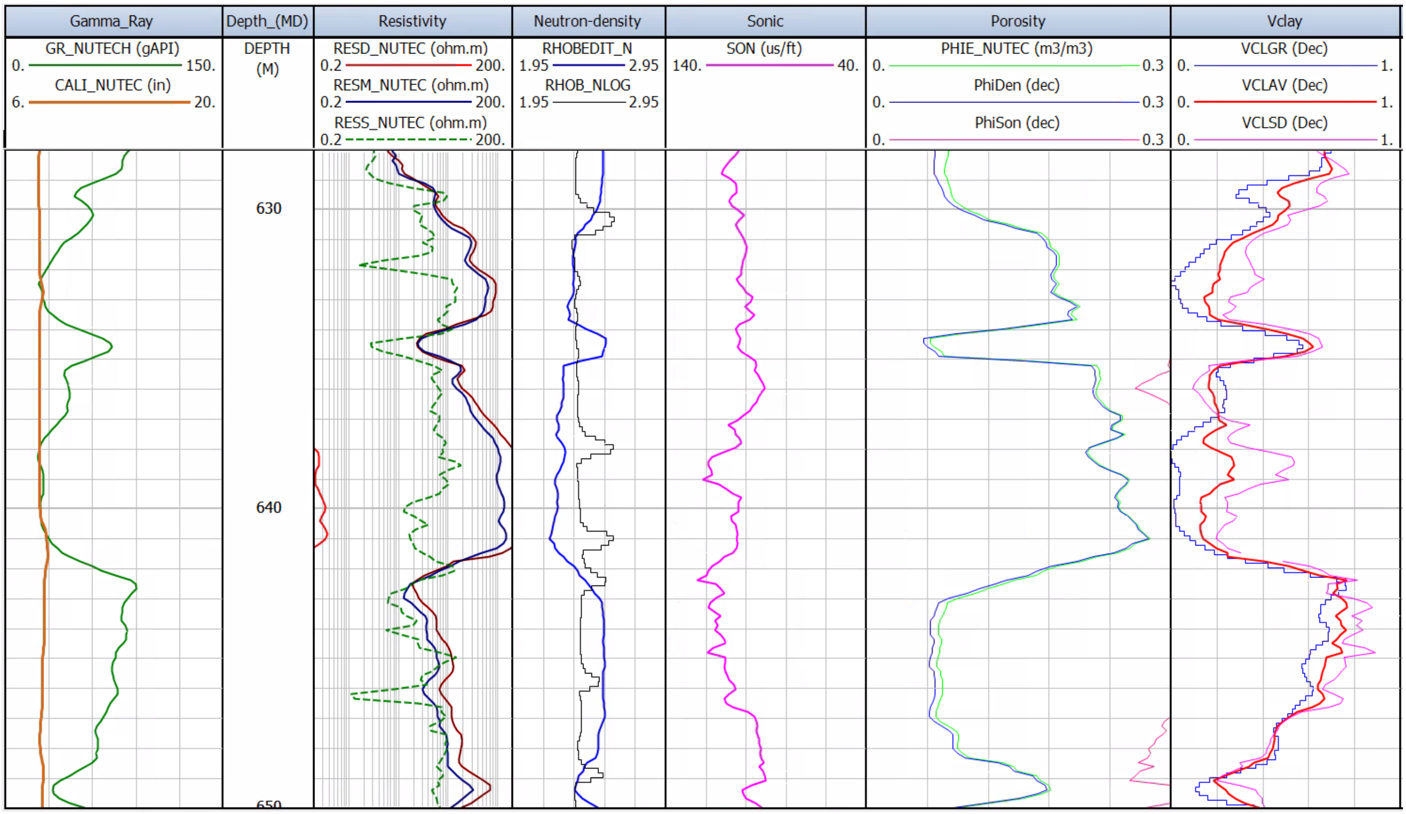


Fig. 10. Example of the results of the calculation of porosity and clay volume in Interactive Petrophysics (IP) software (Well MKP-10)

In track 6 (porosity) of **Fig. 10** can be observed that the porosity derived from the density log matches very well with the effective porosity log from NUTECH (2013), based on this the density-derived porosity was always used as the effective porosity for the wells where this log is available; where not, neutron porosity always gave a good approximation.

The porosity modelled from well logs was then populated for each of the facies in the reservoir grid using Sequential Gaussian Simulation (using the properties in the six mentioned wells as input). The clay average volume (V_{cl}) from single clay indicator and double clay indicators was populated for each of the facies using a Gaussian random function simulation with volumetric co-Krigging (porosity being the secondary variable with a correlation coefficient of -1, for assuring high volumes of clay are allocated in cells with low porosity).

An average net to gross (N/G) of 40% is reported by NAM (1995) for the Moerkapelle reservoir within the three units considered in the geological model (KNNSR, SLDNR and SLDND). In order to match the N/G of the complex geological model with that reported by NAM (1995), a clay volume cutoff of 45% and a porosity cutoff of 6% was applied (this is mainly due to the fact of the presence of heavy oil in the reservoir, which would only flow in the very porous and permeable rocks). The cells with V_{cl} bigger than the cutoff or porosities lower than the cutoff were assigned a porosity of 0 (which means a N/G of 0, because the rock quality is not good enough to allow flow of very viscous oil). **Fig. 11** exhibits the porosity distribution obtained from well logs compared to the porosity distribution populated in the 3D grid once the cutoffs were applied. It can be observed how many of the low well log porosities (lower than 15%) are assigned porosities of 0 in the 3D grid, while for the high porosities there is a good correlation between the percentages of grid and well logs porosities. It is also noticeable that the N/G for the 3D grid is 40% (all the cells with porosities different than 0 have a N/G equal to 1).

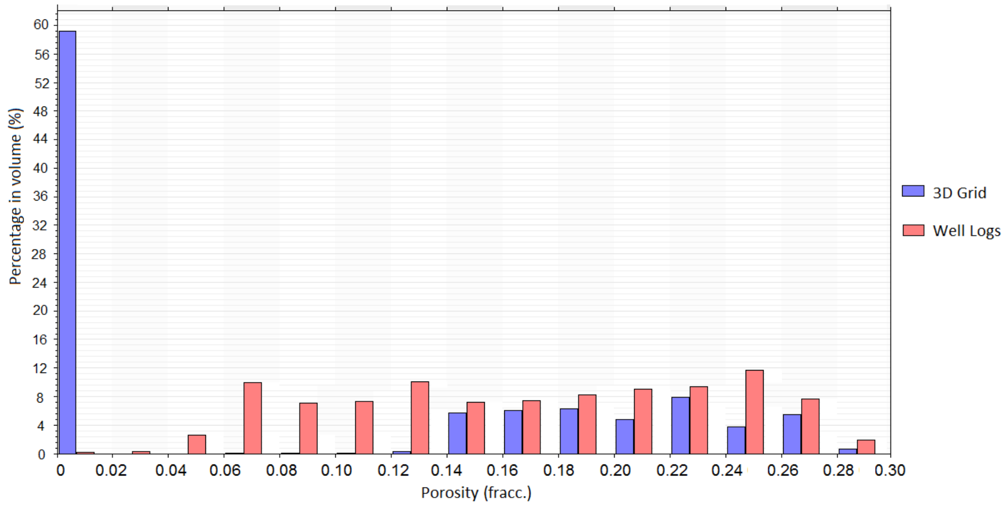


Fig. 11. Histogram (in volume) of the 3D populated porosity vs. Well logs porosity for the Base Case realization (KNNSR, SLDNR and SLDND). It can be seen that the N/G of the whole model is 40% (percentage in volume of all the cells with porosity different than 0 in the 3D grid)

The calculation of the permeability was carried out based on the correlations obtained by Smits (2008) for the Delft sandstone in different areas (**Fig. 12**). There is a significant spread in the permeability data from the Moerkapelle field seen in **Fig. 12**, even though, no facies diferenciation was done by Smits (2008). Due to the lack of the raw data presented in **Fig. 12**, that allow to develop new equations per facies; the existing correlations were used for each of the 3 sandstone facies on the constructed geological model as shown in **Table 10.** The permeability distribution calculated for the SLDND is shown in **Fig. 13**.

Table 10. Porosity-permeability relations used for different facies in the SLDND. For the KNNSR the levee correlation was used

Facies	Correlation
Channel fill	$k = 0.1474e^{36.788\phi}$
Point bars	$k = 0.052e^{30.210\phi}$
Natural dike-levee	$k = 0.0762e^{32.552\phi}$

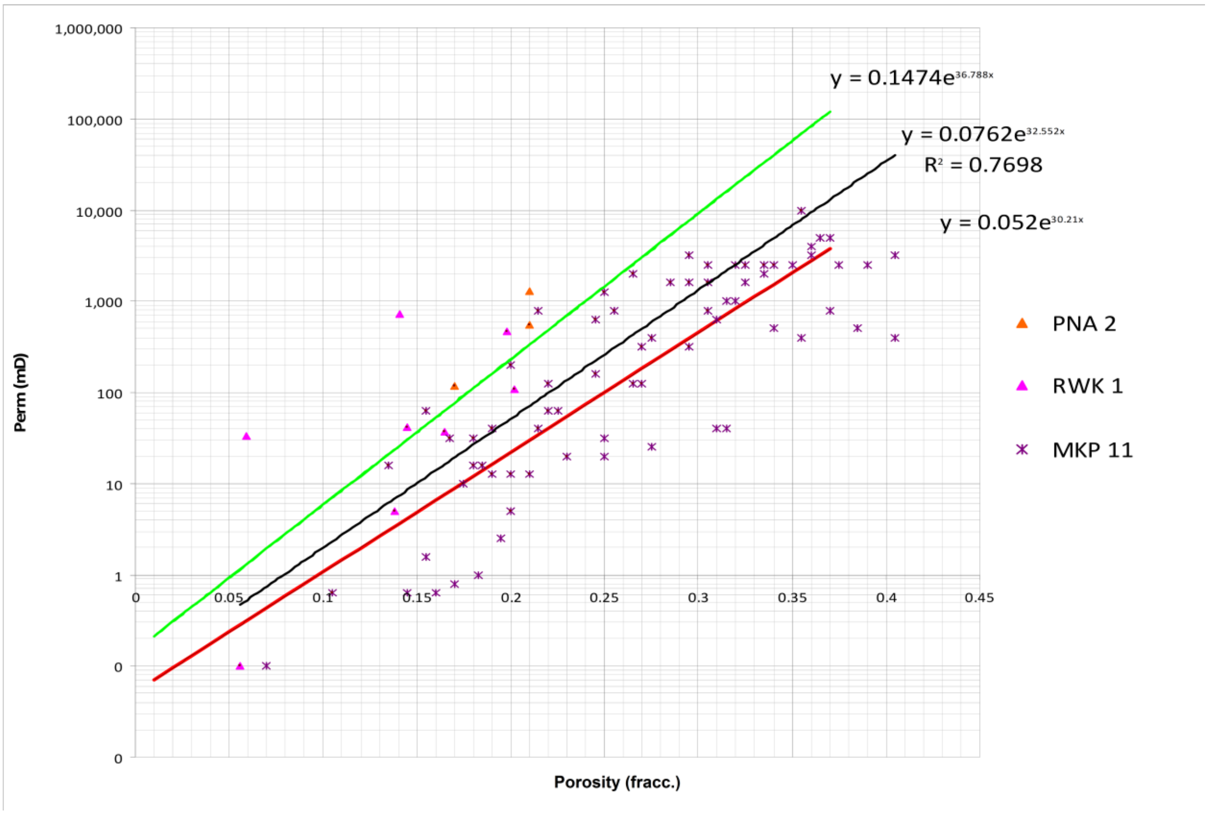


Fig. 12. Porosity- permeability relations for the Delft Sandstone in different areas. After Smits (2008). PNA: Pijnacker, RWK: Rijswijk, MKP: Moerkapelle

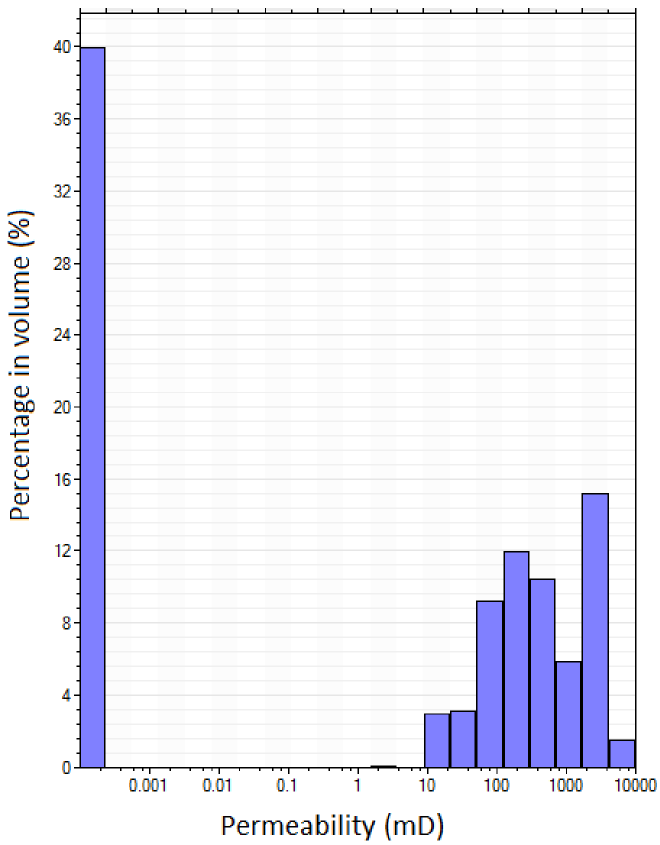


Fig. 13. Histogram (in volume) of the 3D populated permeability for the Base Case realization (Only SLDND). It can be seen that the N/G of only the SLDND is 60% (volume percentage of all the cells with permeability different than 0)

3.3.2. Reservoir Simulation

In Stage 3 the reservoir simulation was developed only for scenario F (200 m well spacing, this was selected as the best scenario in terms of economics during *Stage 2*). Besides the complexity of the sedimentology itself, capillarity was also included in this stage; this is a factor that has not been considered in the previous stages nor in ZiabakhshGanji et al. (2016). A preset capillary pressure curve from Petrel was used for all the sandstone facies in the reservoir in order to determine if capillarity is a critical parameter affecting the oil production and should be taken into account in any future studies (capillary pressure curves are one of the missing information from the Moerkapelle field and the DSSM).

Simulations were also run in a 3-doublet scenario (scenario G) because of the feasibility of this pattern observed during *Stage 2* (see section **4.2.3**). The location of the wells in scenario G is illustrated in **Fig. 14** and their characteristics are the same as those summarized in **Table 5** for scenario F.

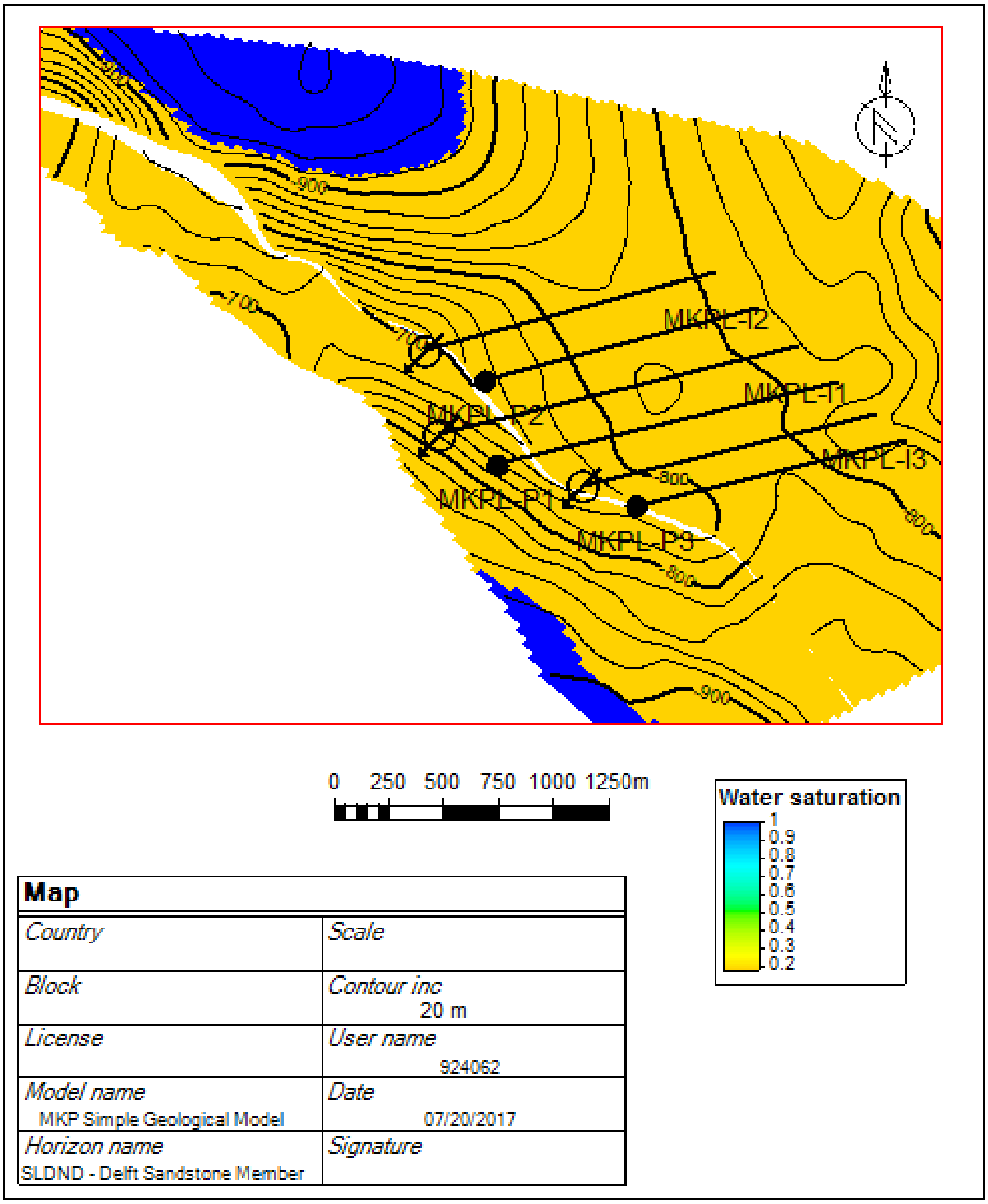


Fig. 14. Scenario G on Contour map for the top of DSSM (SLNDND). Colors in the map represent water saturation (oil saturation is yellow). One pattern with three doublets (scenario G) is illustrated by black continuous lines

3.3.3. Economic Analysis

The calculation of the NPV for the geothermal and EOR side of the project was done and then added up to obtain the NPV of the synergy. Different methods of calculating the costs were used for the two parts of the project (their main assumptions are shown in **Table 6** and **Table 7**).

3.3.4. Heat Production

The heat production at this stage was calculated assuming the same parameters as in *Stage 2* (see **Eq. 1** and **Table 8**). The heat production is assumed to be realized through the transfer of heat from the produced fluids (oil and water) to a heating fluid (probably water) in a heat exchanger on the surface.

3.3.5. Total Energy Production

The total energy production was calculated in the same way as in the *Stage 2;* by expressing the oil production in terms of energy (using the crude heat content) and summing up the energy obtained from the oil to the heat obtained from the geothermal side of the project

4. Results

In this section the results obtained from simulations of the different stages are presented. Parameters calculated from the results of the simulations (as heat and total energy production) that are necessary for developing the economic analysis are also shown. Most of the results are presented on graphs instead of numbers, since for the project it is important to analyze how they behave over time.

4.1. Stage 1*. Homogeneous Box Model*

Cumulative oil production over time for four different scenarios are presented in **Fig. 15**; additional information on the performance of the wells is illustrated in **Appendix E**. In this stage it was learnt that the thermal breakthrough time (time at which hot fluids from the oil reservoir start to be produced in the producer well) controls the incremental oil production for the warm water injection scenario (see Scenario D and Scenario D_Cold in **Fig. 15**), and it is strictly dependent on the well spacing. Efforts are made in the next stages on making the thermal breakthrough time earlier than the maximum injection time so that heat generation on the surface remains constant (heat from water not arriving to surface since all is being injected is replaced by heat produced from warm water co-produced with oil).

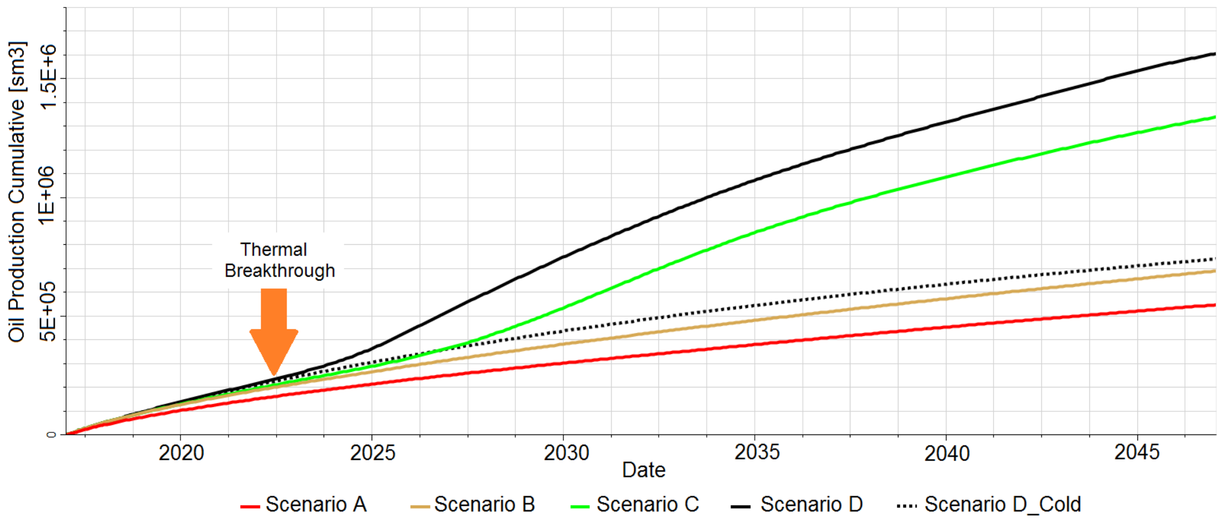


Fig. 15. Cumulative oil production from different scenarios in the homogeneous box model. (see **Table 3** for more information on the scenarios)

Analysis from now on will be only performed on scenario C (doublet) which constitutes the base case for the upcoming stages; this is mainly because it provides the highest amount of oil for a single doublet (Scenario D considers presence of more wells in the field). Sensitivity analyses on parameters as well placement and grid size were carried out in scenario C. The effect of well placement in the simple box model (no geometry involved) goes up to 10% reduction in cumulative oil production. Differences in oil production between 10 m and 15 m grid are very subtle, meaning the results on the 15 m grid are numerically-accurate for a practical case. More information on the sensitivity analyses can be found in **Appendix F**.

4.2. Stage 2*. Homogeneous Simple Reservoir Model*

4.2.1. Oil Production

Cumulative oil production for the different scenarios in *Stage 2* are presented in **Fig. 16** and **Fig. 17**. During the simulation and results analysis of the different scenarios, we identified rock compressibility as a key parameter that affects the final oil and water production profiles. Sensitivity analysis on rock compressibility was carried out in scenario F (Second *Step*) comparing the value used by ZiabakhshGanji *et al.* (2016) with Petrel presets for unconsolidated sandstones and one obtained from well logs; it was determined that there is a big difference in oil production between the case with the value used by ZiabakhshGanji *et al.* (2016) and the other cases. However, compressibility used by ZiabakhshGanji *et al.* (2016) continue to be used in this project in absense of any hard data from the Moerkapelle field. More detailed results on the sensitivity on rock compressibility can be found in **Appendix F.3** to **F.6**.

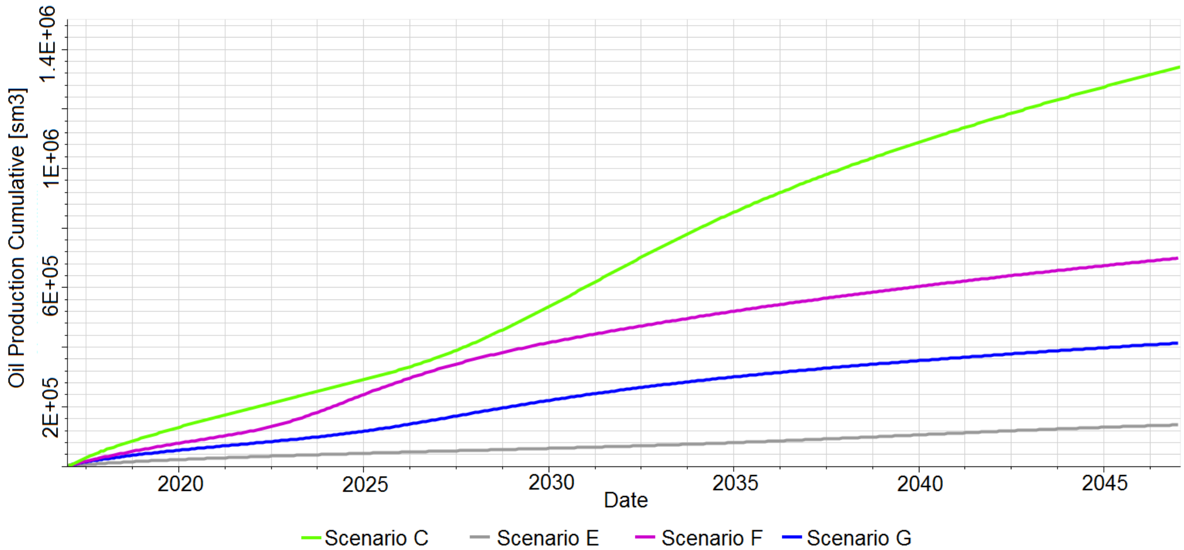


Fig. 16. Cumulative oil production from different scenarios in the homogeneous simple reservoir model, *First step.*

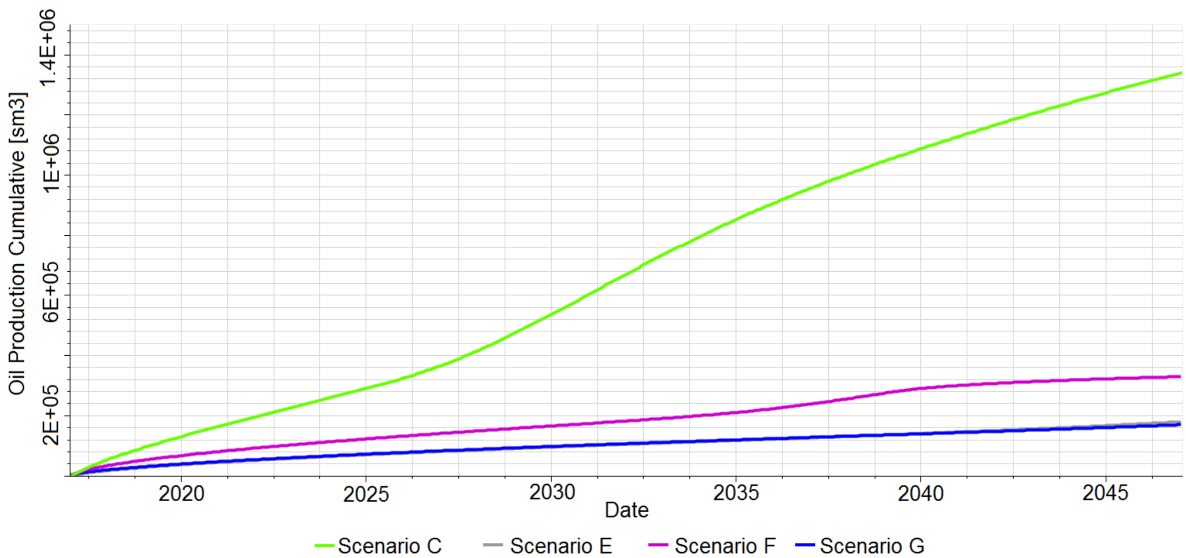


Fig. 17. Cumulative oil production from different scenarios in the homogeneous simple reservoir model, *Second step.* Scenario E almost coincides with scenario G

Scenario F was selected as the most promising in terms of oil production (considering that scenario C is from *Stage 1* and was included in **Fig. 16** and **Fig. 17** for comparison between the two stages). Four cases with different well spacing were run into this scenario in order to determine the optimal well spacing in the economic analysis. Cumulative oil production over time for different well spacing in scenario F is presented in **Fig. 18**. Additional information on the performance of the wells is illustrated in **Appendix G**.

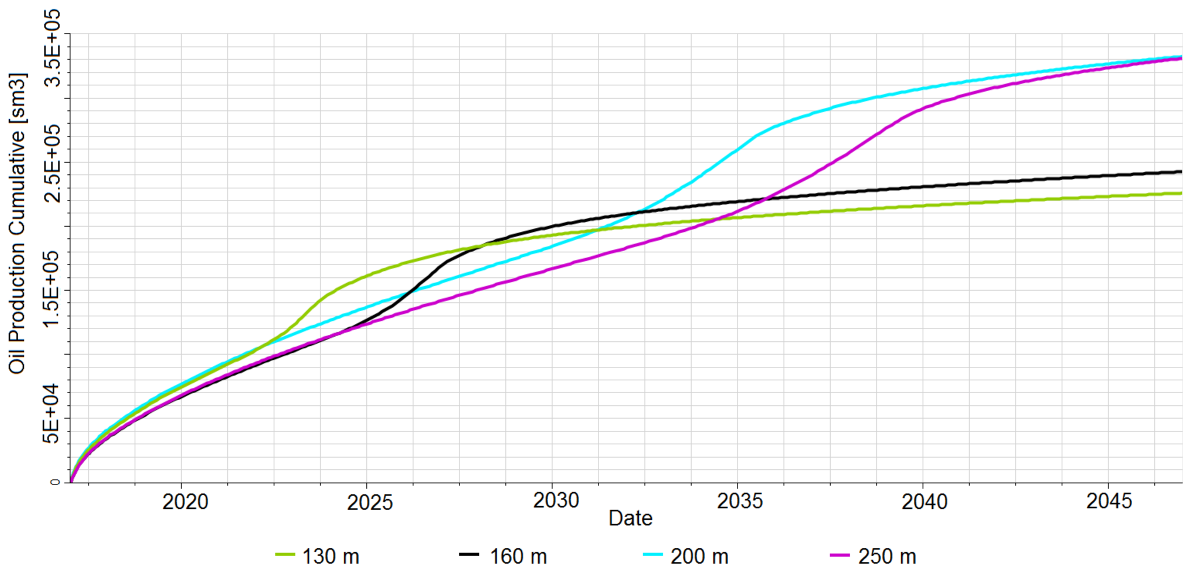


Fig. 18. Cumulative oil production over time for different well spacing in production scenario F

4.2.2. Heat Production

Fig. 19 illustrates the yearly heat production obtained for different well spacing for scenario F; the heat production in all the cases is lower than what would be obtained from a geothermal doublet with constant production rate. Lower heat production profiles for the synergy project are due to energy losses in the heavy oil reservoir (heat transferred to reservoir, overlaying and underlying rocks).

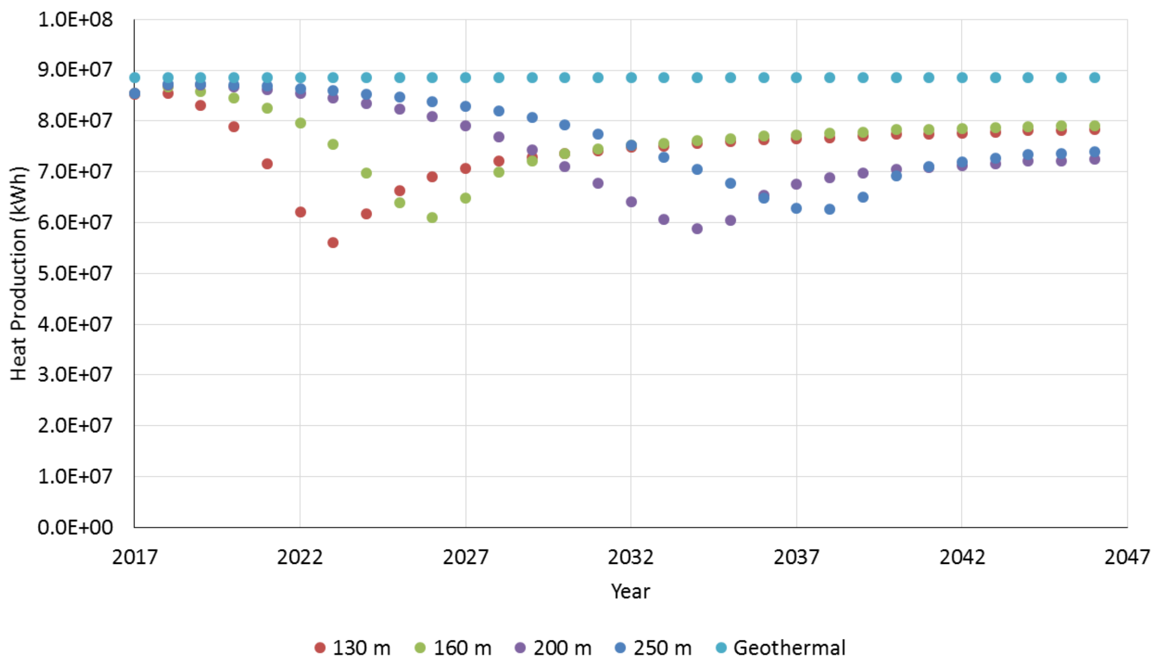


Fig. 19. Heat production profile (yearly) for different well spacing in the production scenario F compared with a stand-alone geothermal doublet with constant production rate of 150 sm³/day

4.2.3. Economic Analysis

The NPV of the geothermal side of the synergy project (30 years' time frame, 2017 to 2047) for different well spacing of scenario F is presented in **Table 11,** as well as the difference between the NPV of this part of the project and the NPV of a purely geothermal doublet with constant production rate. These differences represent, in economic terms, the losses of heat evidenced in **Fig. 19**.

Table 11. NPV of the geothermal side of the project for different well spacing in scenario F and comparisson to a purely geothermal doublet with constant production rate

SCENARIO	GEOTHERMAL NPV	NPV DIFFERENCE-GEOTHERMAL
GEOTHERMAL	€ -19,115,061	€ 0
Scenario F_130m	€ -19,619,592	€ -504,531
Scenario F_160m	€ -19,625,890	€ -510,829
Scenario F_200m	€ -19,397,192	€ -282,131
Scenario F_250m	€ -19,285,948	€ -170,887

Fig. 20 exhibits the NPV evolution of the synergy project over time. Note that the NPV is always negative, as expected for a geothermal project without subsidy. However, the NPV (in 2046) is usually higher than that for a purely geothermal project; this added value is created uniquely by the production of oil.

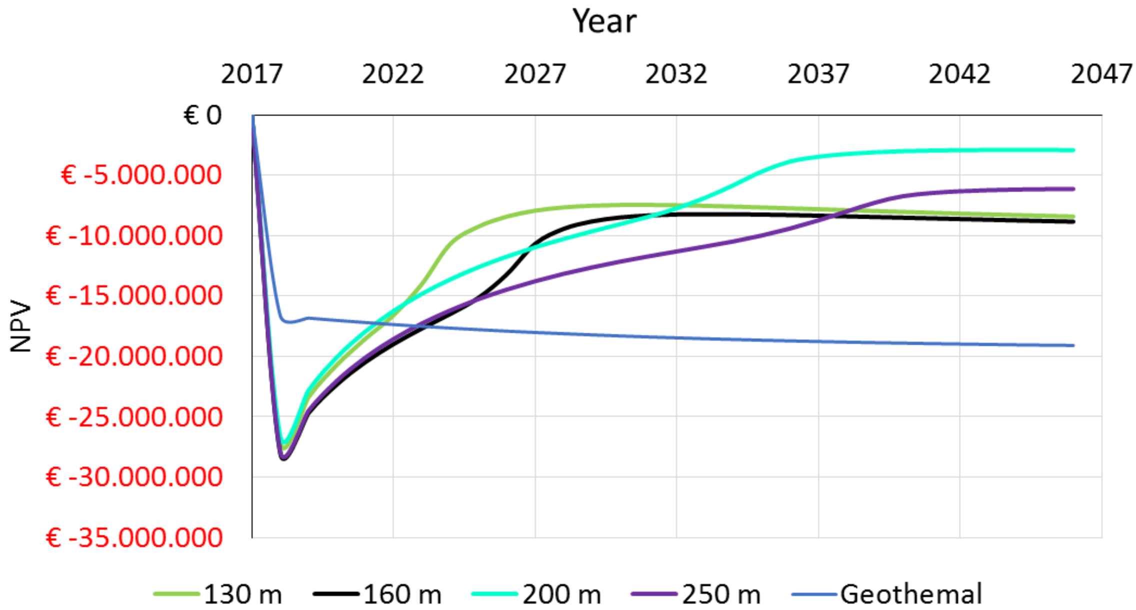


Fig. 20. NPV over time for different well spacing in the production scenario F compared to the NPV of a single-doublet geothermal project

Based on the results of the economic analysis for a single doublet, 200 m was selected as the optimum well spacing to be applied in the following stage. From **Fig. 20** one can deduce that the synergy between geothermal and heavy oil recovery is non-viable when no subsidy is applied to the geothermal side; this is mainly caused by the high cost of the facilities required for water-oil separation and other equipment required for heat transfer and fluid transportation. However, when scaling up the process and considering more than one doublet, the extra oil and heat production obtained could pay for that equipment. As an example, simulation with 3 doublets (one next to each other in a linear pattern) with the same parameters as scenario F (200 m well spacing) was run and economic analysis was developed in the very same way as before. **Fig. 21** illustrates the NPV evolution of this case, in this case the NPV of the up-scaled process is positive and the project becomes economically more attractive.

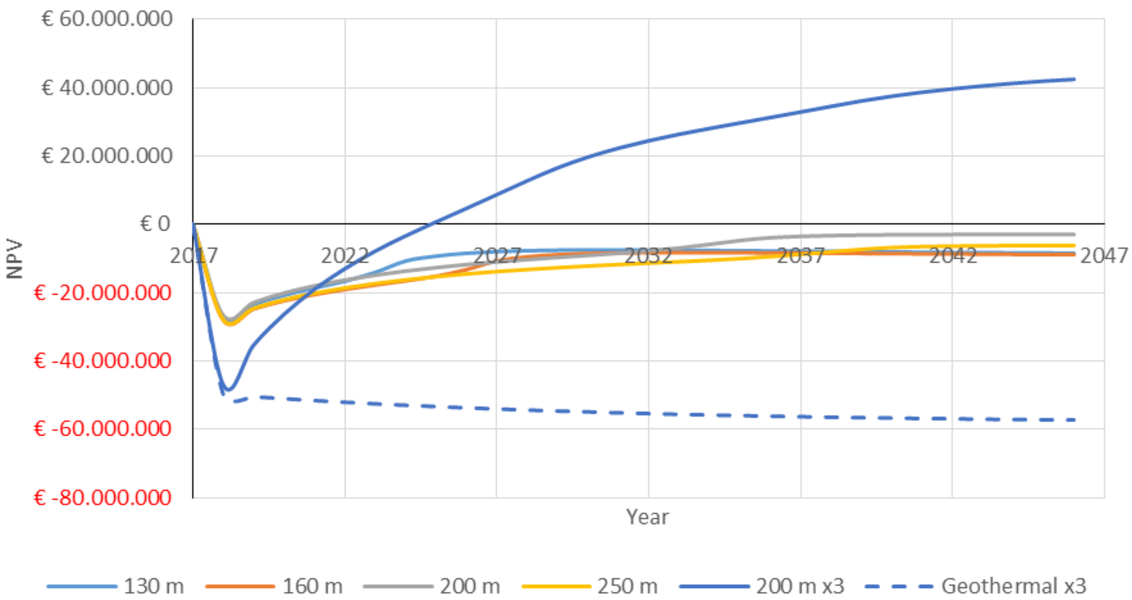


Fig. 21. NPV over time for different well spacing in the production scenario F compared with the up-scaled project, consisting of 3 producers and 3 injectors

Note that in the NPV in 2018 **Fig. 21** for the 3 doublets scenario goes down to -€50MM euro, this is due to the high oil and water production rates that scale up the size of the required production facilities (less than for a 3-doublet geothermal project since oil production is obtained from 2017). However, such production also bring benefits in terms of income that makes the NPV positive within five years. Details on oil production and well performance in general for the 3 doublets scenario can be found in **Appendix H**.

4.2.4. Total Energy Production

Fig. 22 illustrates the yearly total energy production (Oil & Geothermal) obtained for different well spacing in scenario F while **Fig. 23** shows its corresponding cumulative energy production. The total energy production is, in all the cases, higher than what would be obtained from a geothermal doublet with a constant production rate. Even in cases where the synergy project may not be interesting from an economic point of view (single doublets); the extra production of energy compared to a geothermal project makes it viable from the enthalpy side (energy point of view). "*From an enthalpy point of view, the project is always interesting whenever the amount of energy obtained is bigger than the energy invested on it"* (*i.e.* the amount of energy produced in the synergy is bigger than that would be obtained from a stand-alone geothermal project without any oil production).

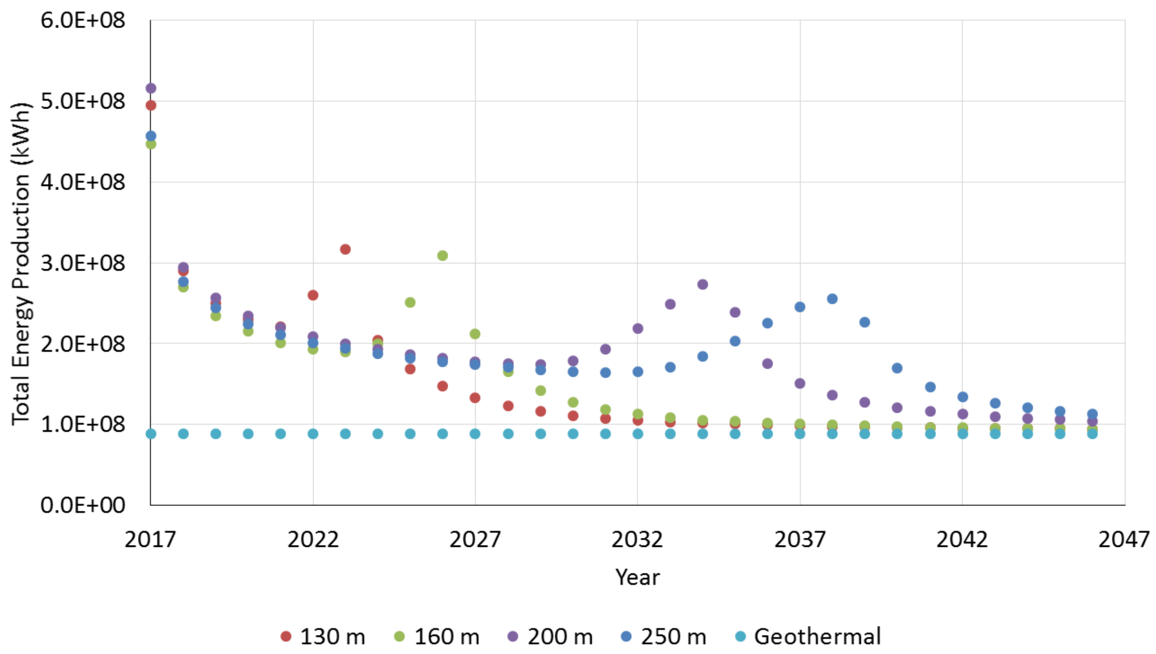


Fig. 22. Total energy production profile (yearly) for different well spacing in the production scenario F compared with a stand-alone geothermal doublet with constant rate of 150 sm^3/day

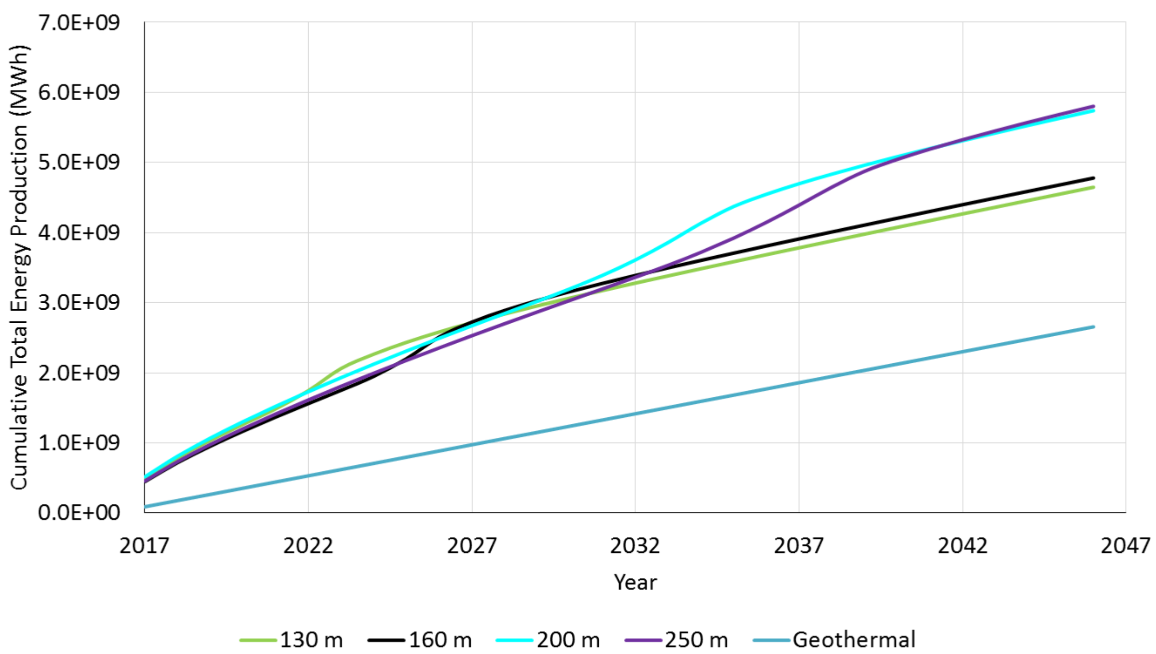


Fig. 23. Cumulative total energy production profile for different well spacing in the production scenario F compared with a stand-alone geothermal doublet with constant rate of 150 sm^3/day. Delta in energy production is purely due to energy content of the produced oil

4.3. Stage 3. *Heterogeneous Reservoir Model*

4.3.1. Scenario F

4.3.1.1. Oil Production

In **Fig. 24** the cumulative oil production of scenario F in the base case realization is exhibited, two cases (with and without capillarity) are compared. From **Fig. 24** can be concluded that there are no significant differences induced by capillarity in terms of oil production. In spite of that fact, capillarity was taken into account for the sensitivity analysis of the effects of the geology (several runs for different realizations), the results of such effects are shown in **Fig. 25.**

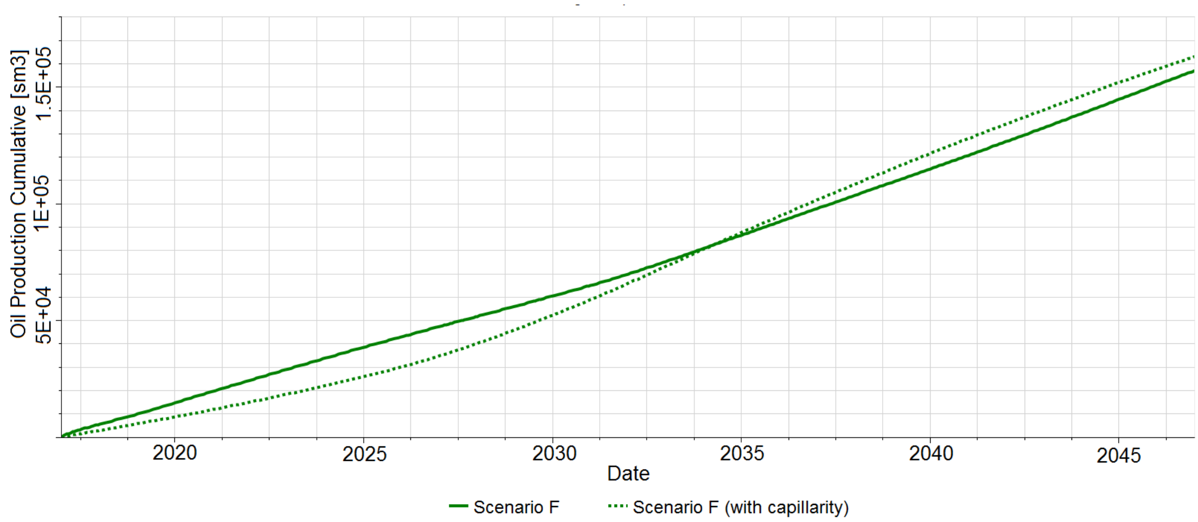


Fig. 24. Cumulative oil production over time in the production scenario F (200 m well spacing) with and without capillarity

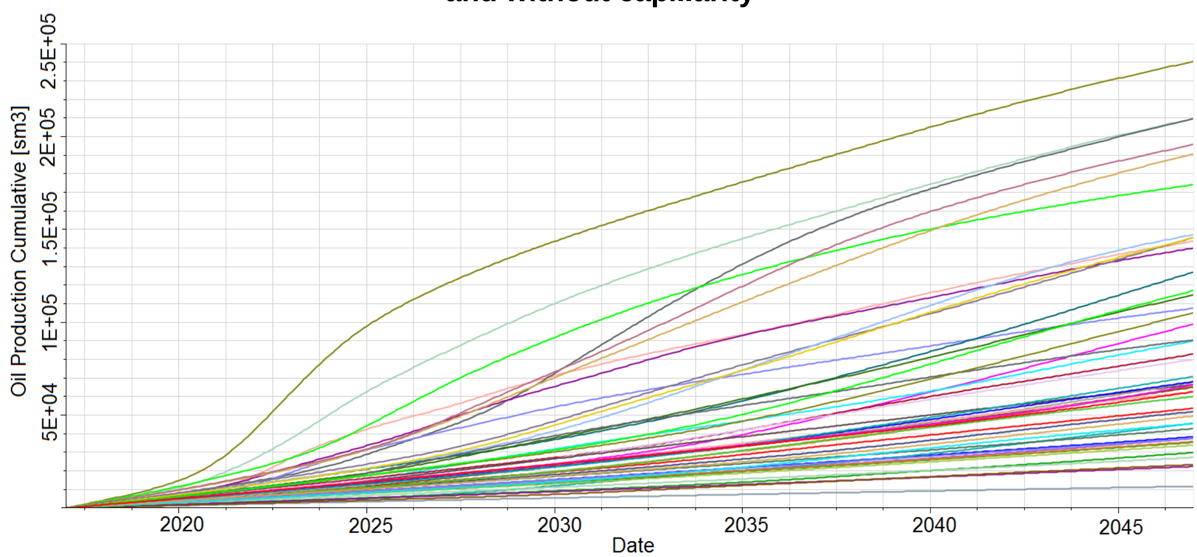


Fig. 25. Cumulative oil production over time in the production scenario F (200 m well spacing) for 50 different facies realizations

There is a wide variation in the cumulative oil production depending on the position of the good porosity-good permeability rocks (located in the channels) within the reservoir. After extensive analysis of the results it was determined that the main parameters determining these differences are the oil initially in place within the drainage area of the injector and the producer and the amount (and quality) of sand penetrated by the wells; this hypothesis is better developed in section **4.3.3**.

4.3.1.2. Heat Production

Fig. 26 illustrates the yearly heat production obtained for different realizations for scenario F in the Heterogeneous Reservoir model; heat production is always lower than what would be obtained from a purely geothermal project with constant production rate due to energy losses in the heavy oil reservoir.

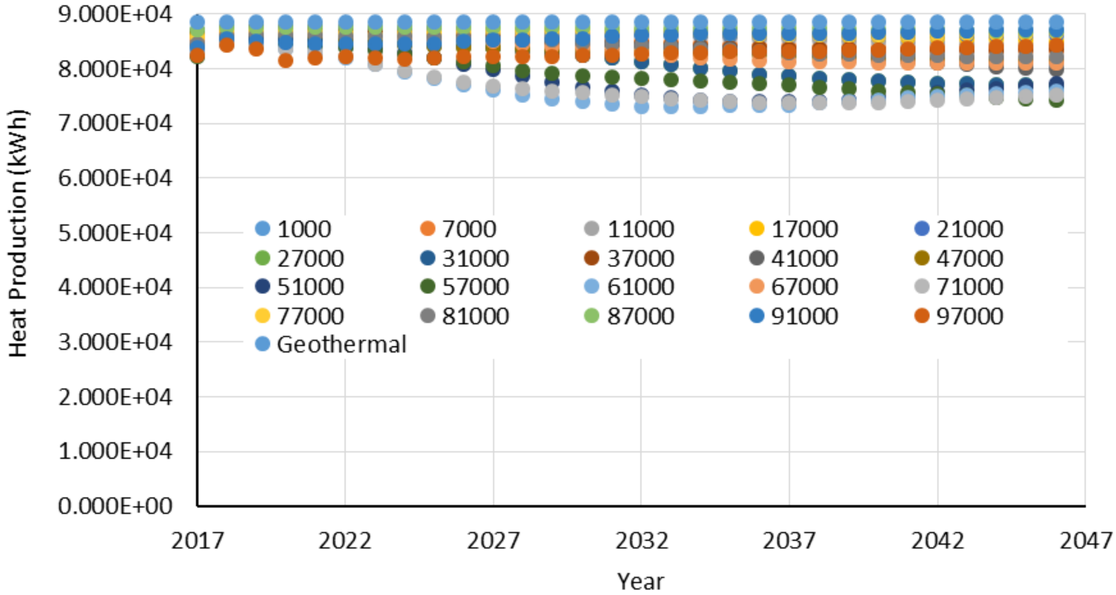


Fig. 26. Geothermal heat production profile (yearly) for different realizations in production scenario F (Heterogeneous Reservoir model). Results are compared with a stand-alone geothermal doublet with a constant production rate of 150 sm^3/day. The number of the realization indicates the seed used in the facies modelling for that specific case

4.3.1.3. Economic Analysis

Economic analysis was developed for 20 of the 50 realizations in the Heterogeneous Reservoir Model; **Fig. 27** exhibits the NPV evolution of the synergy project (single doublet) over time for different realizations. For the Heterogeneous Reservoir Model, the NPV (in 2046) is not always higher than the total NPV for a purely geothermal project (Around € -19MM showed in **Table 11,** Scenario F_200m), this means oil is not always adding value to the project.

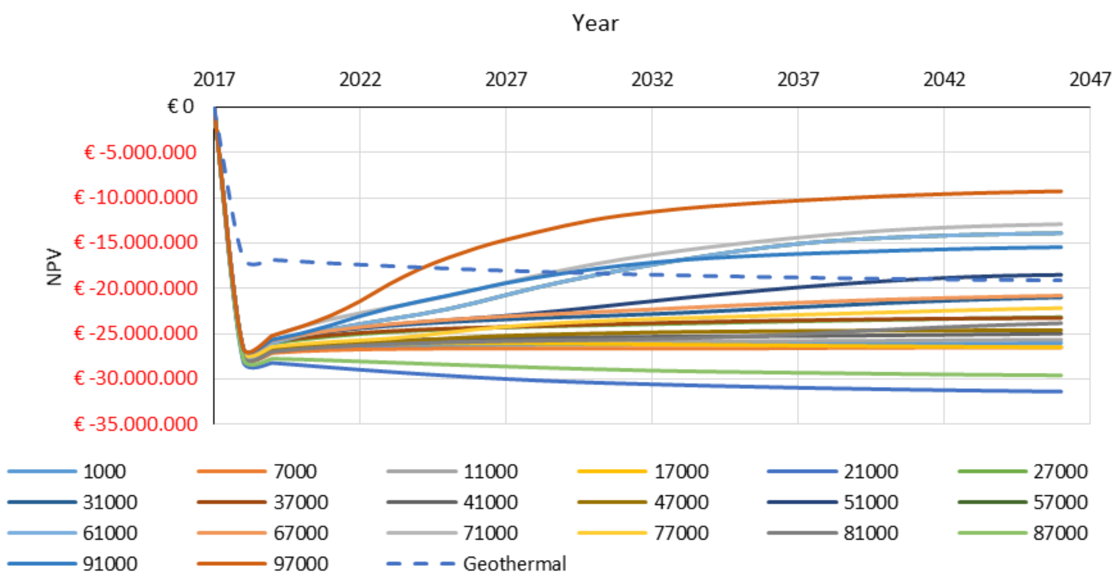


Fig. 27. NPV over time for different realizations in the production scenario F (Heterogeneous Reservoir Model) compared to the NPV of a single-doublet geothermal project

In **Fig. 27** the effect of heterogeneity on the NPV of the synergy project can be seen. The synergy between geothermal and heavy oil recovery is not economic when no subsidy is applied to the geothermal side (for a single doublet). For these heterogeneous reservoirs, however, there are some cases (*e.g.* realization 21000) in which the oil side does not add any value to the project, but instead makes the NPV to decrease over time. In these cases the OPEX of both sides of the project is always higher than the income from oil and heat sales.

4.3.1.4. Total Energy Production

Fig. 28 illustrates the yearly total energy production (Oil & Geothermal) obtained for different realizations for scenario F in the Heterogeneous Reservoir model. The total energy production is always higher than that obtained from a geothermal doublet with a constant production rate. The extra production of energy makes the project viable from the enthalpy side (*i.e.* the amount of energy produced in the synergy is bigger than that would be obtained from a stand-alone geothermal project without any oil production), but not from the commercial point of view. **Fig. 29** shows the corresponding cumulative energy production.

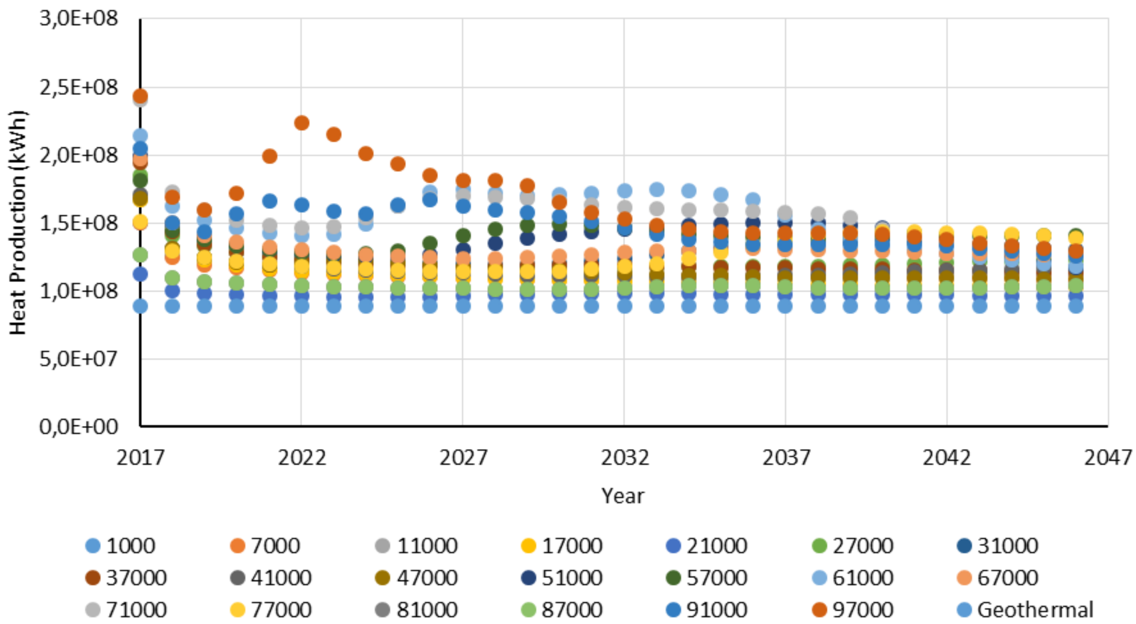


Fig. 28. Total energy production profile (yearly) for different realizations in production scenario F (Heterogeneous Reservoir model) compared with a stand-alone geothermal doublet with a constant rate of 150 sm^3/day. The number of the realization indicates the seed used in the facies modelling for that specific case

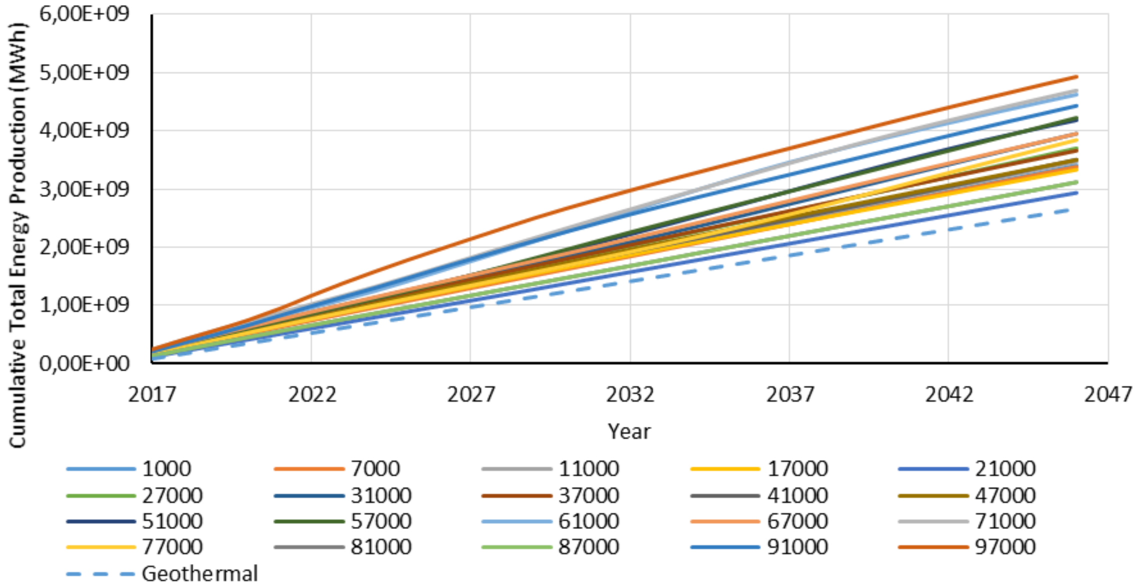


Fig. 29. Cumulative total energy production profile for different realizations in production scenario F (Heterogeneous Reservoir model) compared with a stand-alone geothermal doublet with a constant rate of 150 sm^3/day. The number of the realization indicates the seed used in the facies modelling for that specific case

4.3.2. Scenario G

4.3.2.1. Oil Production

Cumulative oil production for the different realizations in scenario G are presented in **Fig. 30**. The range of variation in the cumulative oil production is still wide compared to that for scenario F (see **Fig. 25**); but in this case more cases are clustered close to the average. The effect of the position of the good porosity-good permeability rocks within the reservoir and the other parameters considered in section **4.3.3** is attenuated when up-scaling the project to more than one doublet.

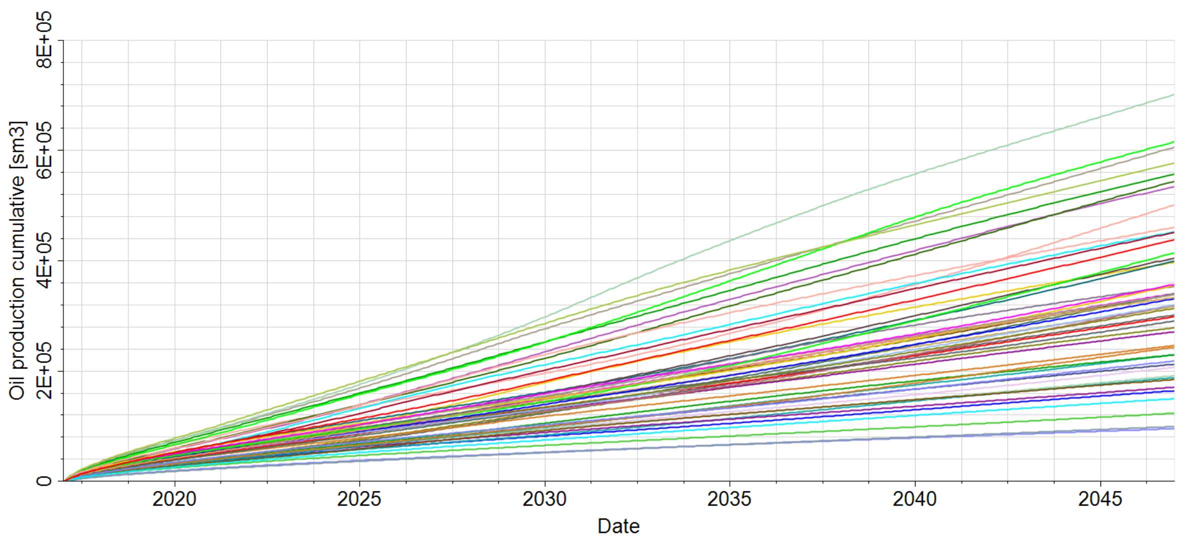


Fig. 30. Field cumulative oil production over time in the production scenario G (200 m well spacing – 3 doublets) for 50 different facies realizations

4.3.2.2. Heat Production

Fig. 31 illustrates the yearly heat production obtained for different realizations in scenario G. Heat losses in scenario G (differences to stand-alone geothermal) are bigger than in scenario F (see **Fig. 26**) since the volume of reservoir rock being drained is bigger (6 wells instead of 2) and therefore the amount heat transferred to reservoir is higher.

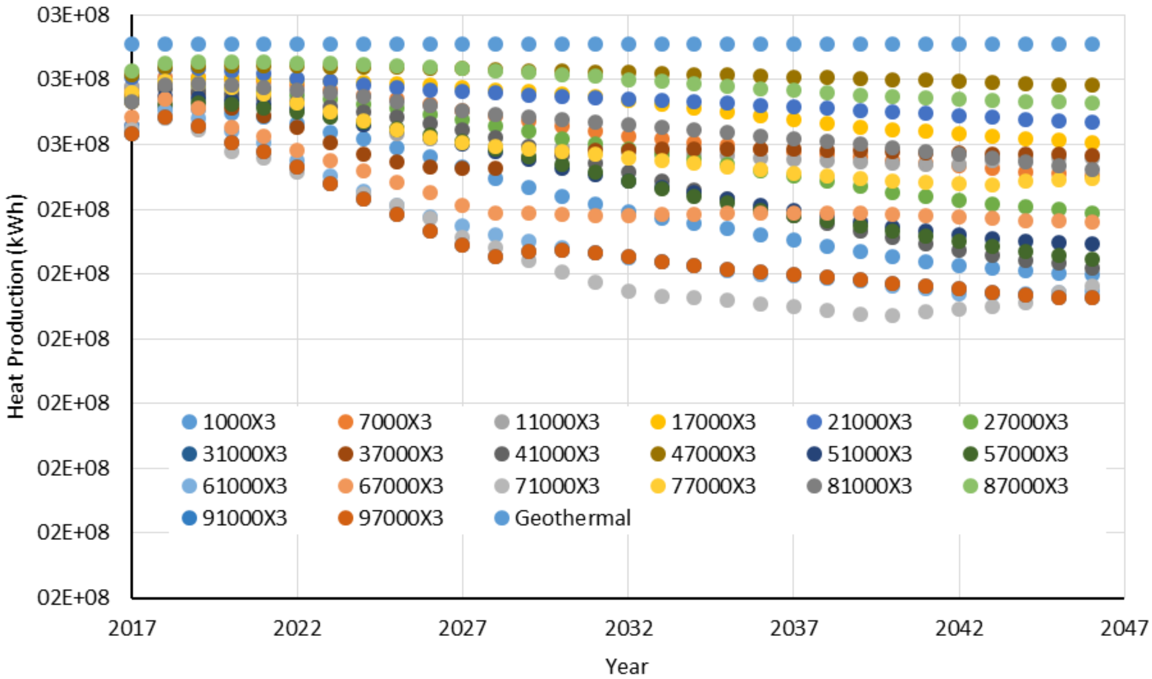


Fig. 31. Heat production profile (yearly) for different realizations in the production scenario G compared with a stand-alone geothermal 3-doublets project with constant production rate of 150 sm^3/day per doublet. The number of the realization indicates the seed used in the facies modelling for that specific case

4.3.2.3. Economic Analysis

Fig. 32 exhibits the NPV evolution of the synergy project (three doublets) over time for different realizations. For only one case of scenario G (realization 47000) the final NPV is not higher than the total NPV for a stand-alone geothermal 3-doublets project (Around € -57MM).

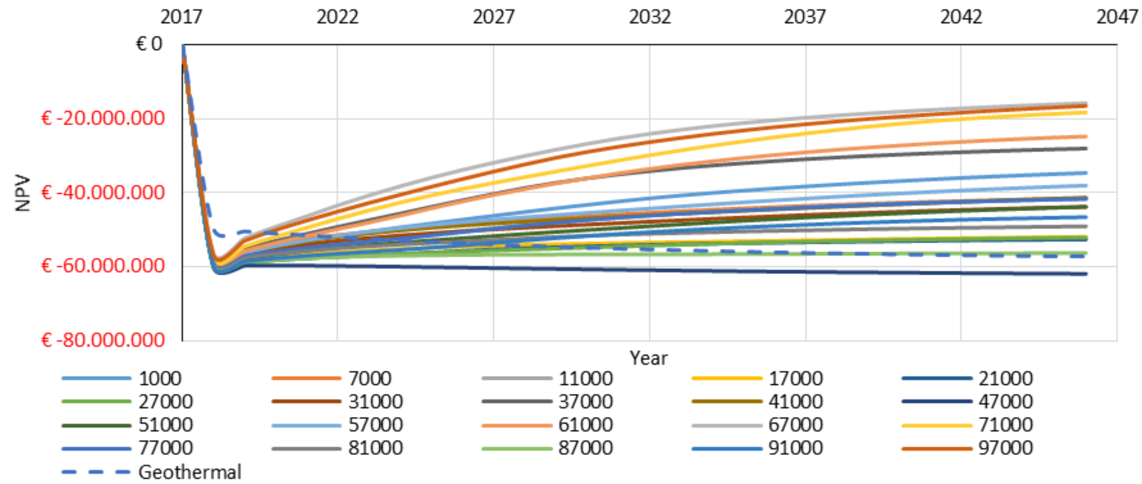


Fig. 32. NPV over time for different realizations in production scenario G (Heterogeneous Reservoir Model) compared to the NPV of a 3-doublets geothermal project

The synergy between geothermal and heavy oil recovery is not economically viable (for all of the cases) when no subsidy is applied to the geothermal side.

4.3.2.4. Total Energy Production

Fig. 33 illustrates the yearly total energy production obtained for different realizations for scenario G in the Heterogeneous Reservoir model and **Fig. 34** shows the corresponding cumulative energy production. The total energy production is always higher than that obtained from a geothermal doublet with a constant production rate. The extra production of energy makes the project viable from the enthalpy side.

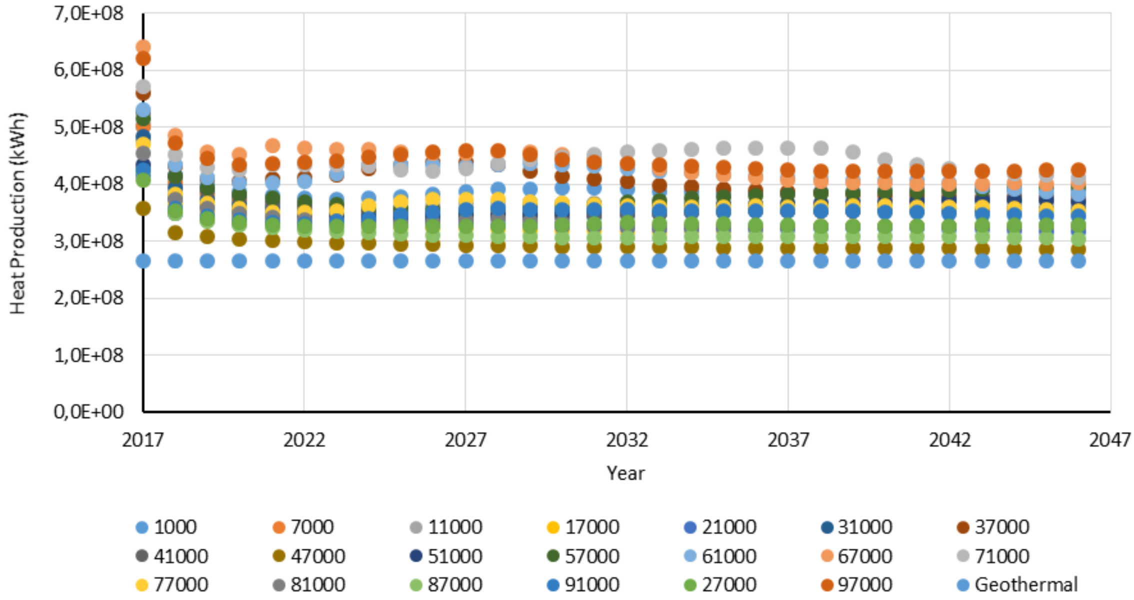


Fig. 33. Total energy production profile (yearly) for different realizations in production scenario G compared with a stand-alone geothermal 3-doublets project with a constant rate of 150 sm³/day per doublet. The number of the realization indicates the seed used in the facies modelling for that specific case

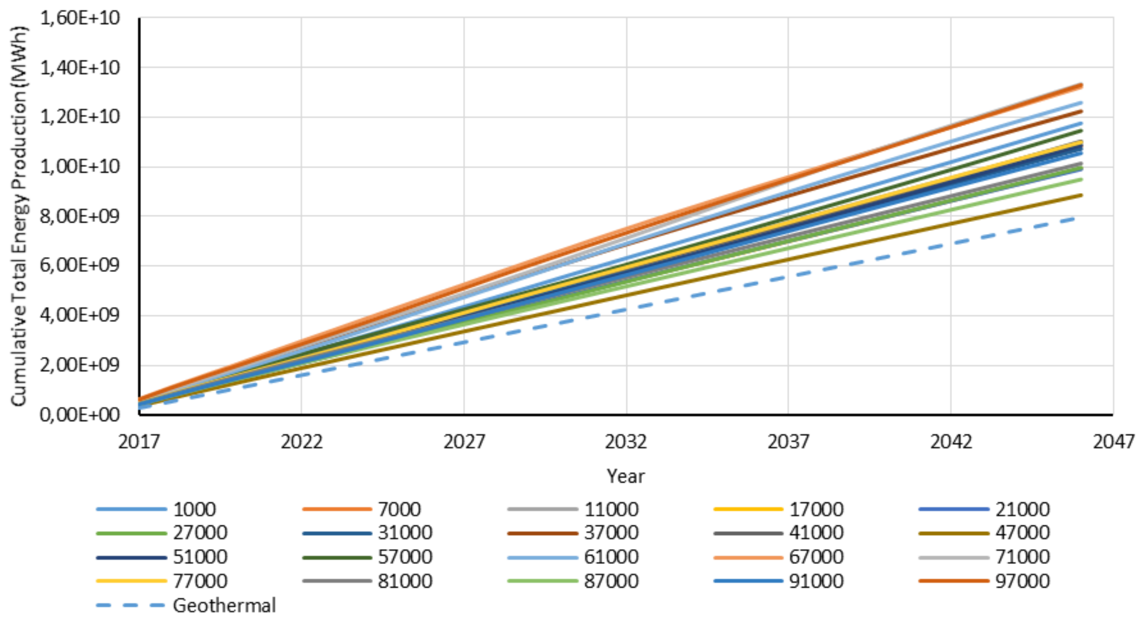


Fig. 34. Cumulative total energy production profile for different realizations in production scenario G compared with a stand-alone geothermal 3-doublets project with a constant rate of 150 sm³/day per doublet. The number of the realization indicates the seed used in the facies modelling for that specific case

4.3.3. Main parameters determining the wide variation on the cumulative oil production for different realizations (Scenario F)

Analysis on several parameters was performed on Scenario F in order to determine the factors causing the wide variation between realizations. **Fig. 35** shows the dependency of the cumulative oil production on the oil initially in place (STOIIP); for the Heterogeneous Model a clear dependency can be observed. However the recovery factor varies from 2% to 17%, another factor such as those illustrated in **Figs. 36** to **38** is playing a role in this variation.

On the other hand, for the Homogeneous Model, the STOIIP within the drainage area in the homogeneous model is in general lower than the heterogeneous model due to the fact that the average porosity is 8% (since the homogeneous porosity of 21% multiplied by the N/G of 40%) while in the Heterogeneous Model the average porosity is 12% (see **Fig. 36**)

Homogeneous Model High and Homogeneous Model Low in **Fig. 35** correspond to additional cases run in the homogeneous model using average values of permeability (within the drainage area) from the Heterogeneous Model cases close to the highest and lowest recovery factors (blue dots close to green and orange lines). From this it can be deduced that there is also a dependency of the cumulative oil production on the mean permeability within the drainage area. Different mean permeabilities within the drainage area are obtained from different porosity distributions as those in **Fig. 35**.

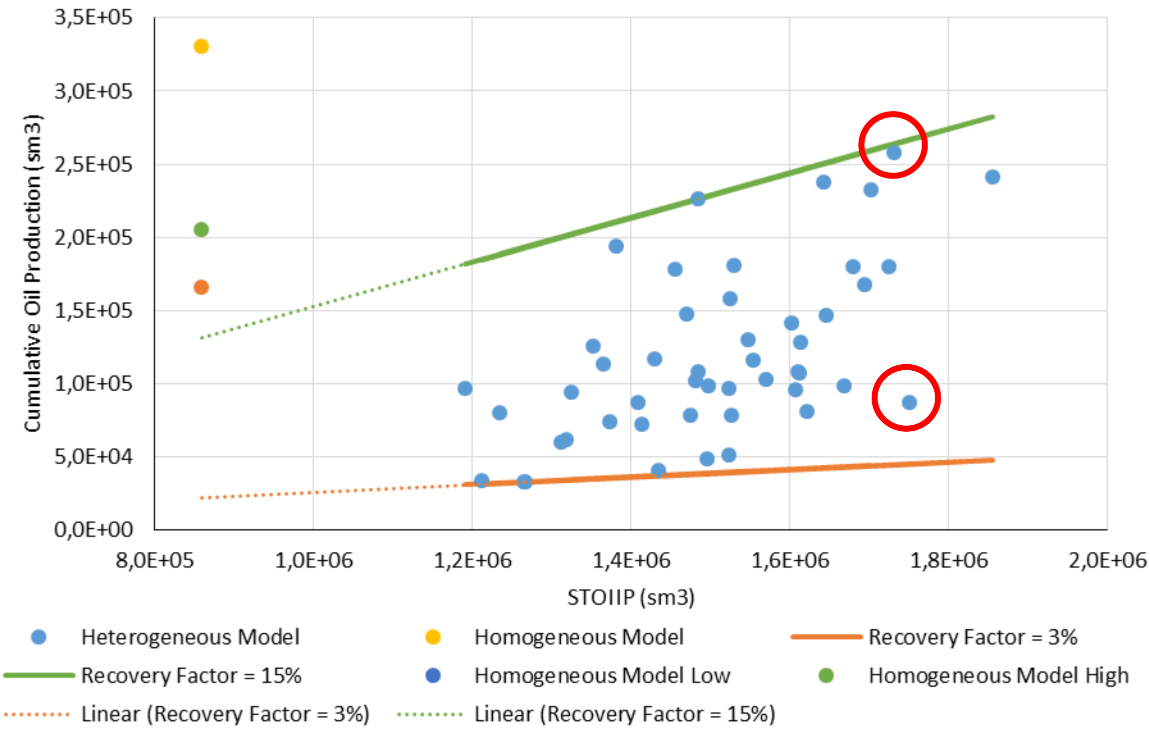
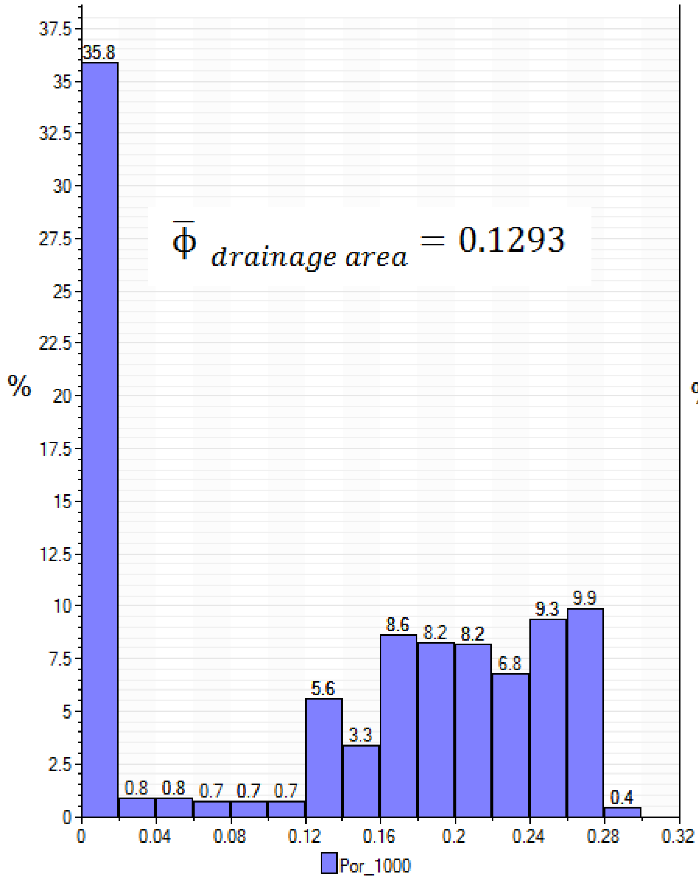


Fig. 36. Dependency of the cumulative oil production on the STOIIP within the drainage area. The drainage area is defined as a 200 m radius from the wells (injector and producer). Red circles highlight the cases selected for analysis in Figs. 36 to 38, represent similar STOIIP with very different recovery factors (high case: realization 93000, low case: realization 1000). Homogeneous Model High (k=460 mD) and Homogeneous Model Low (k=312 mD)

Fig. 36 shows the histogram of the porosity in the drainage area for the realizations selected in **Fig. 35**. The average porosity in the drainage area is similar for both realizations. However, realization 93000 (best in terms in oil production in **Fig. 36**) exhibits bigger volumes of rock with porosities higher than 25% (due to the exponential dependency of permeability, this means permeability higher than 1000 mD).

Fig. 37 illustrates the connected pore volume for the realizations selected in **Fig. 35**. The connected pore volume is a property that can be obtained in Petrel by setting a porosity cutoff (21% was used, similar to the porosity in the Homogeneous Model) to determine the cells that are connected to the wells, in this case was done within the drainage radius between the injector and producer in scenario F. The connected pore volume in realization 1000 is $5.2x10^5$ m^3 and in realization 93000 is $1.2x10^6$ m^3.



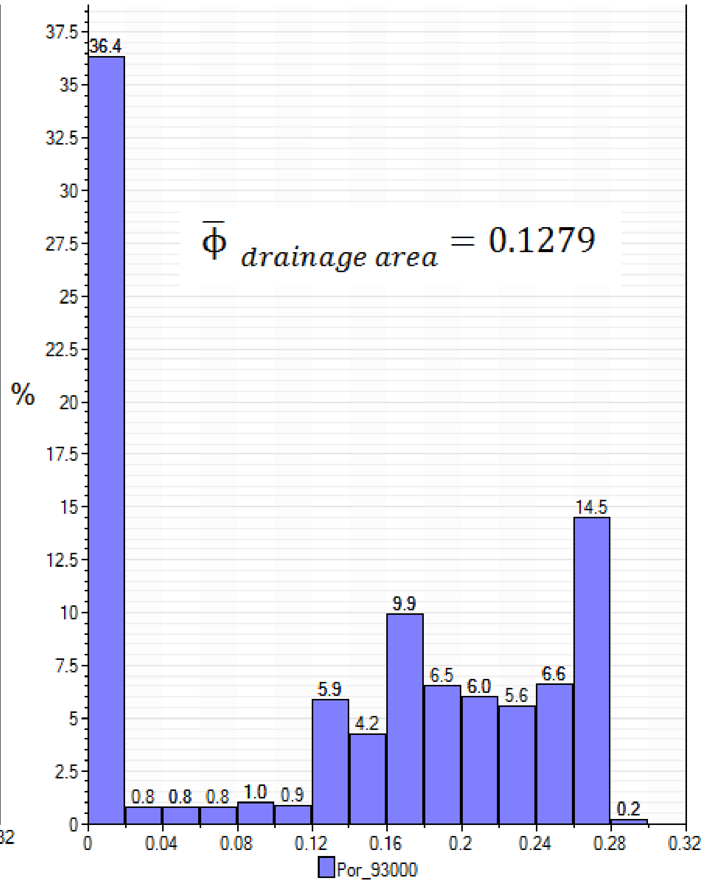
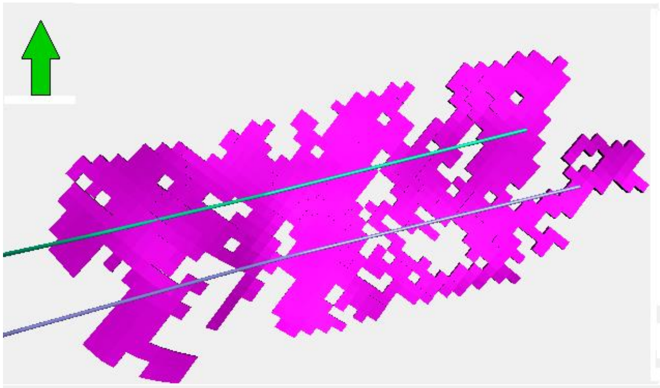


Fig. 37. Histogram (in volume) of the porosity in the drainage area for realizations 1000 (left) and 93000 (right)



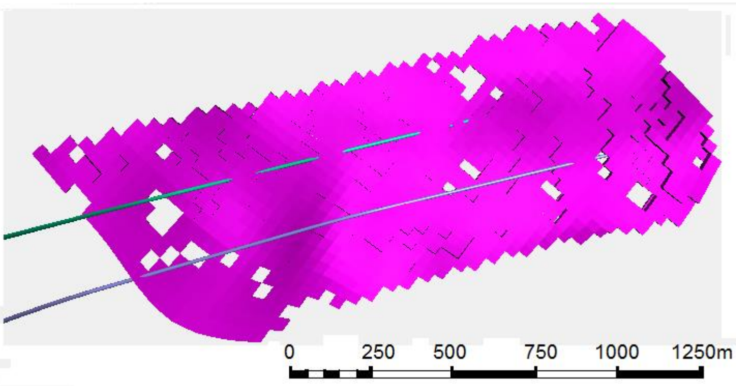


Fig. 38. Connected pore volume within the drainage area (cells in purple) for realizations 1000 (left) and 93000 (right)

Fig. 38 exhibits the porosity encountered by the producer well for two different realizations and the histogram of the porosity encountered by the producer well. Realization 93000 is one of the best cases and 1000 is one of the worst cases in terms of oil production; it can be concluded that in the worst case the wells penetrate more shale (porosity=0) and less good quality rocks (permeability>500 mD). This is due to the fact that the wells are always kept in the same position while changing the position of the channels (changing the seed).

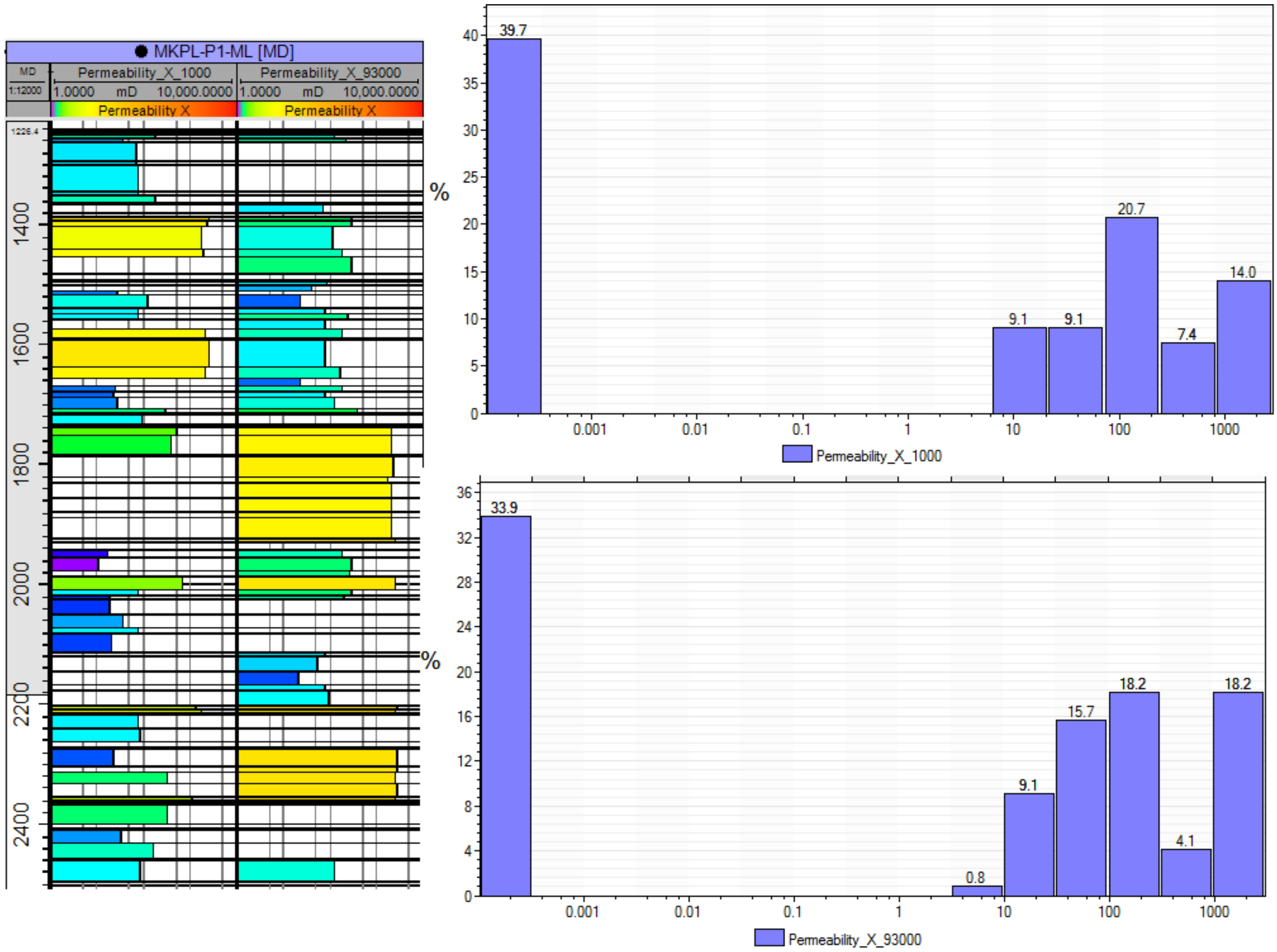


Fig. 39. (Left) Porosity encountered by the producer well for two different realizations (Seed= 1000 & 93000). (Right) Histogram (in length) of the porosity encountered by the producer well, Seed=1000 (Top) & Seed=93000 (Bottom)

5. Discussion

The main focus of the work is on the modelling of the recovery from the oil reservoir, while productivity and temperature of the geothermal source is assumed to be constant. The changes in parameters and in the model itself for each stage were decided on the results obtained in the earlier stage. In this chapter the analysis of the obtained results is carried out and the main factors affecting the feasibility of the project are discussed.

5.1. Stage 1*. Homogeneous Box Model*

The homogeneous box model was constructed as a preliminary screening, *i.e.* in order to know if under the best circumstances (homogeneous-isotropic reservoir of known dimensions and without any geometry acting as a flow barrier) the injection of water from a geothermal reservoir to a heavy oil reservoir adds any value to the geothermal project. Even though no economic or energy production analysis was conducted at this early stage, it was decided that the incremental production of 850000 sm^3 per producer-injector doublet of scenario D vs. scenario D_Cold (see **Fig. 15**) would make the project interesting from an economic point of view. It also means that it make sense to continue adding complexities to the geological model in the next stages.

There is a significant difference in terms of oil production between the $1.3x10^6$ sm^3 obtained in scenario C and the $5.0x10^5$ sm^3 reported by Ziabakhsh-Ganji *et al.* (2016) for a 100 °C geothermal reservoir after 10000 days (close to the 30 years of scenario C). Such differences are explained by the improved productivity of horizontal wells, as well as the location of the wells itself (in the middle of the reservoir vs. in the edges of the reservoir in Ziabakhsh-Ganji's *et al.* model). Based on the improvement in oil production, it was decided to use horizontal wells in the following stages.

Best results in this stage were obtained for 250 m well spacing (Scenario C). However, efforts are made in the next stages on determining an optimum well spacing that maximizes the NPV of the project. STOIIP in the model of Scenario C is $6.3x10^6$ sm^3 and the recovery factor is 21%.

5.2. Stage 2. *Homogeneous Simple Reservoir Model*

5.2.1. **Oil Production**

There is a significant reduction in oil production after the transition from *Stage 1* to *Stage 2*. When the same reservoir properties are applied to both models (*First Step*) the reduction goes up to 46% in the best case ($1.3x10^6$ sm^3 obtained in scenario C vs. $7.0x10^5$ sm^3 for scenario F, see **Fig. 16**). Furthermore, when properties reported by NAM (1995) are populated in *Stage 2 (Second Step)*, the reduction in cumulative produced oil is up to 75% ($1.3x10^6$ sm^3 obtained in scenario C vs. $3.3x10^5$ sm^3 for scenario F, see **Fig. 17**).

Such enourmous differences between the two stages are explained mainly by the effect of geometry (*i.e.* differences in thickness and thikness variability), most likely propagated by the effect of well placement presented in **Appendix F.2**. In *Stage 1* Injector and producer are located in the middle of the reservoir (half-length from top to bottom); while in *Stage 2*, due to structural complexity of the reservoir and dog-leg severity constraints for the wells, the wells are not always located in the middle of the reservoir but are always going from top to bottom (in some segments even going out of the reservoir for a couple of meters). The effect of this variation in the simple box model (no geometry involved) goes up to 10% reduction in cumulative oil production (see **Appendix F.2**). However when geometry complexities are present, the combined effect can be as large as 46%.

Well spacing is a key parameter for the synergy; **Fig. 18** makes evident how different well spacing influences the oil production profile over time. Optimum well spacing is the one that maximizes the NPV of the project; in terms of oil production it is the one that gives the highest amount of oil in the lifetime (200 m and 250 m). 200 m was selected over 250 m as the optimum well spacing to be applied in the following stage, this can be explained from the fact that 200 m well spacing produces more oil in the early stage of the project (see **Fig. 18**) and this early production is more valuable in terms of NPV.

When a 3-doublet scenario is considered, productivity per doubled might be variable, an example of this is presented in **Appendix H**. The variability on the performance of the production wells seems not to be caused by the amount of reservoir (in length – measure depth) that they penetrate (see **Appendix H.1** and **H.3**). Such differences may be also caused by different well placements within the reservoir (their effects were previously discussed and presented in **Appendix F.2**) and variations in thickness within the reservoir.

5.2.2. **Heat Production**

Heat production profiles for different well spacing expressed in **Fig. 19** show the effect of the energy losses in the heavy oil reservoir (heat transferred to reservoir, overlaying and underlying rocks) on the heat production at the surface. Maximum heat production reduction goes up to 38%, occurring between 5 and 20 years after the start of production (depending on the well spacing, larger well spacing produces a delayed reduction of the produced heat). However, after reaching a minimum (coinciding with the thermal breakthrough), heat production recovers to levels of only 16% (130 m and 160 m well spacing) and 21% (200 m and 250 m well spacing) lower than the stand-alone geothermal doublet with constant production rate. In general, taking into account the current very low prices of heat, this reduction is acceptable. This predicted heat production profile would be very useful for agreeing on the amount of energy to be sold to the buyer(s) at a certain period.

5.2.3. **Economic Analysis**

In **Table 11** it can be seen that the effect of the heat production reduction in the project economics is not significant. Reduction in NPV of the geothermal side of the project is only up to 3%, meaning this side is not strongly negatively affected by the energy losses in the oil reservoir.

As stated in section **4.2.3**, the synergy between geothermal and heavy oil production is not economic when no subsidy is applied to the geothermal side; this is mainly caused by the high cost of the facilities required for water-oil separation and other equipment required for heat transfer and fluid transportation. On the other hand it could be stated that for a homogeneous reservoir, developing a single doublet synergy would decrease the required subsidy by 85% (comparing the € -19MM required for a stand-alone geothermal project to the € -3MM required for the 200 m well spacing case, see **Table 11** and **Fig. 20**).

When scaling up the process and considering more than one doublet in a homogeneous reservoir, the extra oil and heat production obtained could pay for the project without requiring any subsidy. The NPV is positive and would be up to €43MM.

5.2.4. Total Energy Production

Cumulative energy production for 200 m and 250 m well spacing is more than twice the amount of energy that would be obtained from a stand-alone geothermal doublet with a constant rate (see **Fig. 23**). Despite the fact that the project may not be interesting from an economic point of view (single doublets without subsidy), the extra production of energy makes it viable from the enthalpy side and makes sense to keep researching on this topic from an academic point of view.

5.3. Stage 3. Heterogeneous Reservoir Model

5.3.1. Oil Production

Besides the wide variation in the cumulative oil production, the average cumulative production from the 50 realizations in *Stage 3* is significantly smaller compared to *Stage 2* (1.0x10^5 sm^3 obtained in scenario F in *Stage 3* vs. 3.3x10^5 sm^3 for scenario F in the *Stage 2*). The factors causing this decrease are purely stratigraphic, and are elaborated in section **4.3.3**.

The main parameters determining the variation in the cumulative production among realizations in *Stage 3* is the STOIIP and the porosity and permeability distribution within the drainage area. Despite this fact, this variable is not playing any role in the differences between oil production of stages 2 and 3. In **Fig. 35** can be observed that the homogeneous model (*Stage 2*) contains less oil in the drainage area than any of the cases in the heterogeneous model (*Stage 3*), but the cumulative oil production is bigger than all of the cases in *Stage 2* (RF=39%). Even when considering the average values of permeability (within the drainage area) from the Heterogeneous Model cases close to the lowest recovery factors, the cumulative oil production is bigger for the homogeneous model than for the heterogeneous. This means that the distribution of properties (porosity and permeability) within the drainage area is more important in terms of contribution to the flow of oil than the average of such distribution (main disadvantage of heterogeneous reservoirs).

The reduction in oil production from *Stage 2* to *Stage 3* appears to be better explained by the connected pore volume when a porosity cutoff is applied (see **Fig. 37**). The connected pore volume in the best of the cases of scenario F (*Stage 3* - realization 93000) is 1.2x10^6 m^3, compared to the pore volume in the drainage area of 1.5x10^6 m^3 in *Stage 2* (all the pore volume is connected in *Stage 2* since it is a homogeneous model).

Some other parameters studied in section **4.3.3** such as the amount (and quality) of sand penetrated by the wells are also important for the wide variation of the results in *Stage 3*. However, not that important to explain its differences to *Stage 2*. The effect of the position of the good porosity-good permeability rocks within the reservoir and the other parameters considered in section **4.3.3** is reduced when up-scaling the project to more than one doublet (scenario G).

5.3.2. Heat Production

Heat production over time for different well spacing in *Stage 3* illustrated in **Fig. 26** and **Fig. 31** is much more constant than the heat production profiles for *Stage 2*. Heat production reduction due to heat losses in the oil reservoir goes up to only 22% in scenario F and 17% in scenario G; however, they seem not to recover after reaching a minimum but stay more or less constant after the thermal breakthrough.

Heterogeneity thus means an advantage in terms of geothermal production (assuming that it is a market advantage to maintain production as constant as possible), this is mainly due to the limitations in injectivity caused by the stratigraphic complexities of the reservoir. During a long portion of the lifetime of the field, injection rates are very small and most of the water from the geothermal reservoir can be used to generate heat at surface.

5.3.3. Economic Analysis

As stated in section **4.3.1.3**, the synergy between geothermal and heavy oil recovery appears to be non-viable for the considered project when no subsidy is applied to the geothermal side (for a single doublet). On the other hand it could also be stated that for a heterogeneous reservoir, developing a single doublet synergy would decrease the required subsidy in up to 52% (comparing the € -19MM required for a stand-alone geothermal project to the € -9MM required for the case 97000, see **Table 11** and **Fig. 27**). However, on average, there is no added value from the synergy; but instead a reduction in the NPV of 13%.

When scaling up the process and considering more than one doublet in a heterogeneous reservoir (scenario G) the required subsidy decreases up to 73% (comparing € -57MM required for a stand-alone 3-doublet geothermal project to the € -16MM required for cases 67000 and 97000 in **Fig. 32**) with an average reduction of 31% when all the cases are considered.

5.3.4. Total Energy Production

Cumulative energy production is up to twice the amount of energy that would be obtained from a stand-alone geothermal doublet with constant rate. Despite the fact that the project may not be interesting from an economic point of view (in a heterogeneous reservoir), the extra production of energy makes it viable from the enthalpy side and makes sense to keep researching on this topic from an academic point of view.

6. Conclusions

The synergy between geothermal and stranded oil fields might add value to geothermal projects under specific conditions; stratigraphic complexity of the oil reservoir is the main constraint determining how positive the impact on the synergy is on the project economics. In extreme cases, the oil side does not add any value to the project, but instead makes the NPV decrease over time.

For a homogeneous reservoir (*e.g.,* a very continuous shallow marine sandstone like the KNNSR), the synergy between geothermal and stranded oil fields may reduce the required subsidy for a single doublet geothermal project up to 85%. Furthermore, if subsidy independence is the objective, scaling up the project to three or more doublets (3 geothermal wells and 3 oil producers) would be the best option in these kind of reservoirs; such configuration would not only reduce the required subsidy to zero but would produce additional profit, making the synergy project attractive from an economic point of view.

In the case that the oil reservoir is heterogeneous (*e.g.,* a fluvial sandstone with meandering channel deposits like the SLDND) the subsidy reduction for a single doublet geothermal project would not be higher than 52% in the most optimistic case. Moreover, when all the realizations are taken into account, there is no added value from the synergy; but instead an average reduction in the NPV of 13%.

In order to make the synergy to add value to the project in heterogeneous reservoirs, scaling up the project to 3 or more doublets is again the best option. An average reduction of 31% in the subsidy required can be achieved by this kind of configuration, with a maximum reduction of 73% in the most optimistic case.

The use of horizontal wells was a key factor for making the synergy add value to a geothermal project. With the configuration of vertical wells proposed by Ziabakhsh-Ganji *et al.* (2016) it would be very difficult to obtain any economic benefit from the synergy; even though such configuration appears to be interesting from the recovery factor point of view and might be economical under different circumstances (oil price related).

An optimal well spacing for the conditions of the northwestern block of the Moerkapelle field, where scenario F and G are located (23 m, average thickness in DSSM) was defined as 200 m. However, variations in reservoir thickness, petrophysical properties of the reservoir, and fluid properties may affect this parameter.

Cumulative energy production is always up to twice the amount of energy that would be obtained from a stand-alone geothermal doublet with constant rate. Despite the fact that the project may not be interesting from an economic point of view given the current conditions, the extra production of energy makes it viable from the enthalpy side and makes sense to keep researching on this topic from an academic approach.

7. Recommendations

- Better understanding of the geothermal reservoir is needed, construction of a geological model for the geothermal reservoir was desired at early stages of this project but was not set as an objective due to lack of information from the deep subsurface in the area (there are no wells drilled deeper than the reservoir area mentioned during this project). However, in the following years it is probable that some deep and ultra-deep geothermal pilots in the Netherlands are going to be drilled. Information derived from such projects, together with existing models for the DSSM geothermal reservoir (*e.g.,* Gilding, 2010) and for oil reservoirs (as the one presented in this document) would be of high interest for future research on the synergy between geothermal and stranded oil fields.

- The Moerkapelle field petrophysical and (specially) fluid models are subject to be updated. PVT information from some wells on the Moerkapelle field was recently shared by NAM, and some other is pending (capillary pressure curves, relative permeability curves, etc.). Repeating of the process developed during this project with known properties for the Moerkapelle field would particularize the results and give a better understanding on wether this field is a good option for this kind of synergy.

- Information from other fields around the world would be very useful to create a complete set of parameters that could be changed in order to analyze the suitability of such fields for the synergy between geothermal and stranded oil fields. The use of analogues may become an important decision making strategy in more advanced stages of this technology.

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Nomenclature

BBLoeq: Barrels of oil equivalent

CAPEX: Capital Expenditure

DSSM: Delft Sandstone Member

EOR: Enhanced Oil Recovery

KNNSR: Rijswijk Sandstone Member

k: Permeability

kW: Kilowatt

kWh: Kilowatt-hour

MM: Millions

N/G: Net to gross

NPV: Net Present Value

OPEX: Operational Expenditure

OWC: Oil-Water Contact

RF: Recovery Factor

SD: Standard Deviation

SLDND: Delft Sandstone Member (as named by TNO)

SLDNR: Rodenrijs Claystone Member

sm^3: Cubic meters at standard conditions

STB: Stock Tank Barrels

STOIIP: Stock Tank Oil Initially In Place

TVDSS: True Vertical Depth Subsea

USD: Dollar of the United States

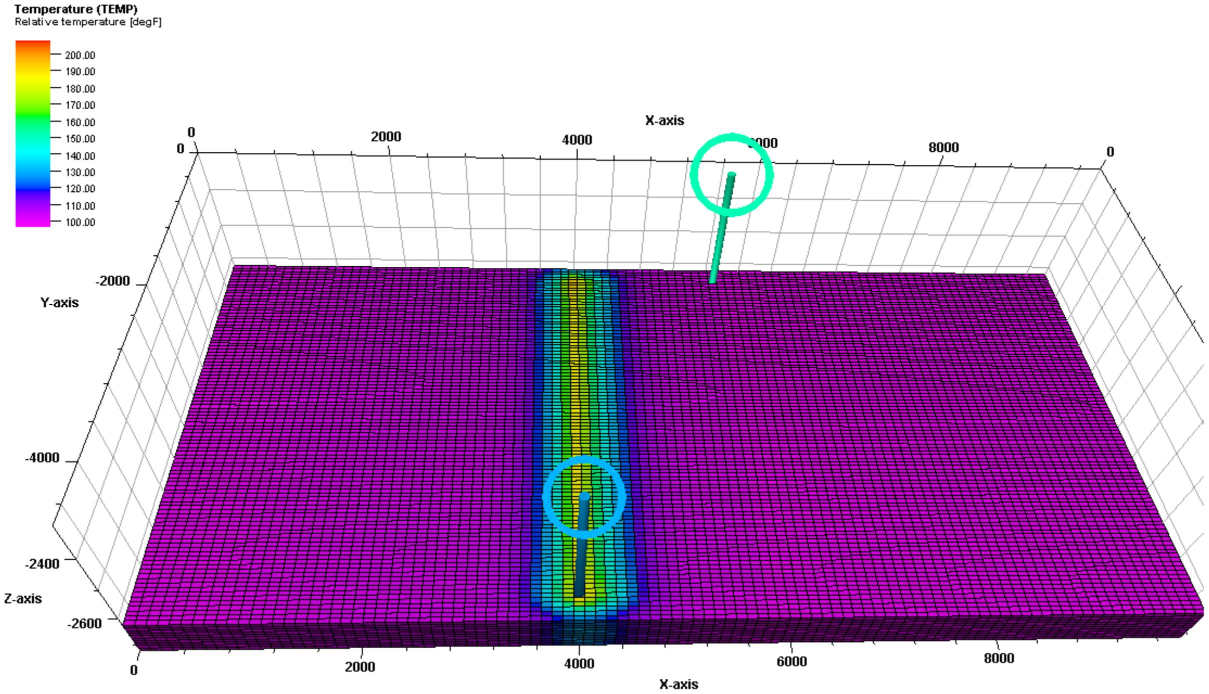
WNB: West Netherlands Basin

€: Euro

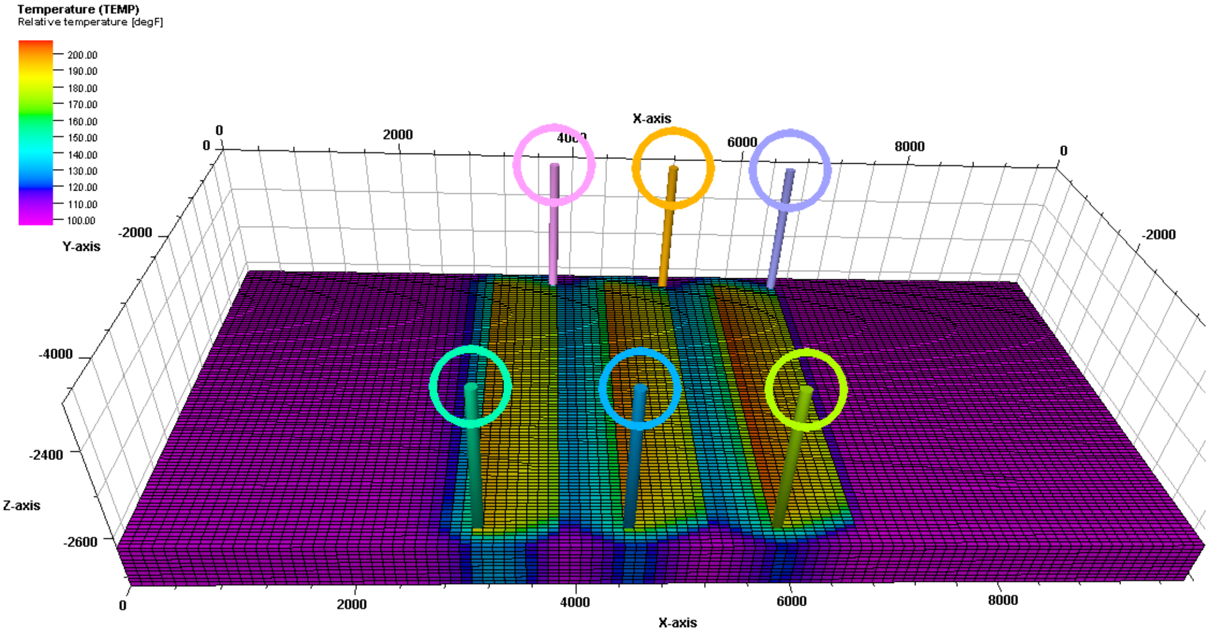
Symbol List

Symbol	Variable	Units
Q	Heat	[kWh]
ρ	Density	[kg/m^3]
V	Volume	[m^3]
C_p	Specific heat	[J/kgK]
ΔT	Change of temperature	[K]
ϕ_s	Porosity derived from sonic	[%]
ϕ_{den}	Porosity derived from density	[%]
Δt	Sonic Slowness	[µs/ft]
M	Confined Modulus	[Pa]
C_r	Rock compressibility	[1/bar]
V_p	Acoustic sonic log velocity	[m/s]
K_{fl}	Fluid modulus	[bar]
C_{fl}	Fluid compressibility	[1/bar]

Appendix A

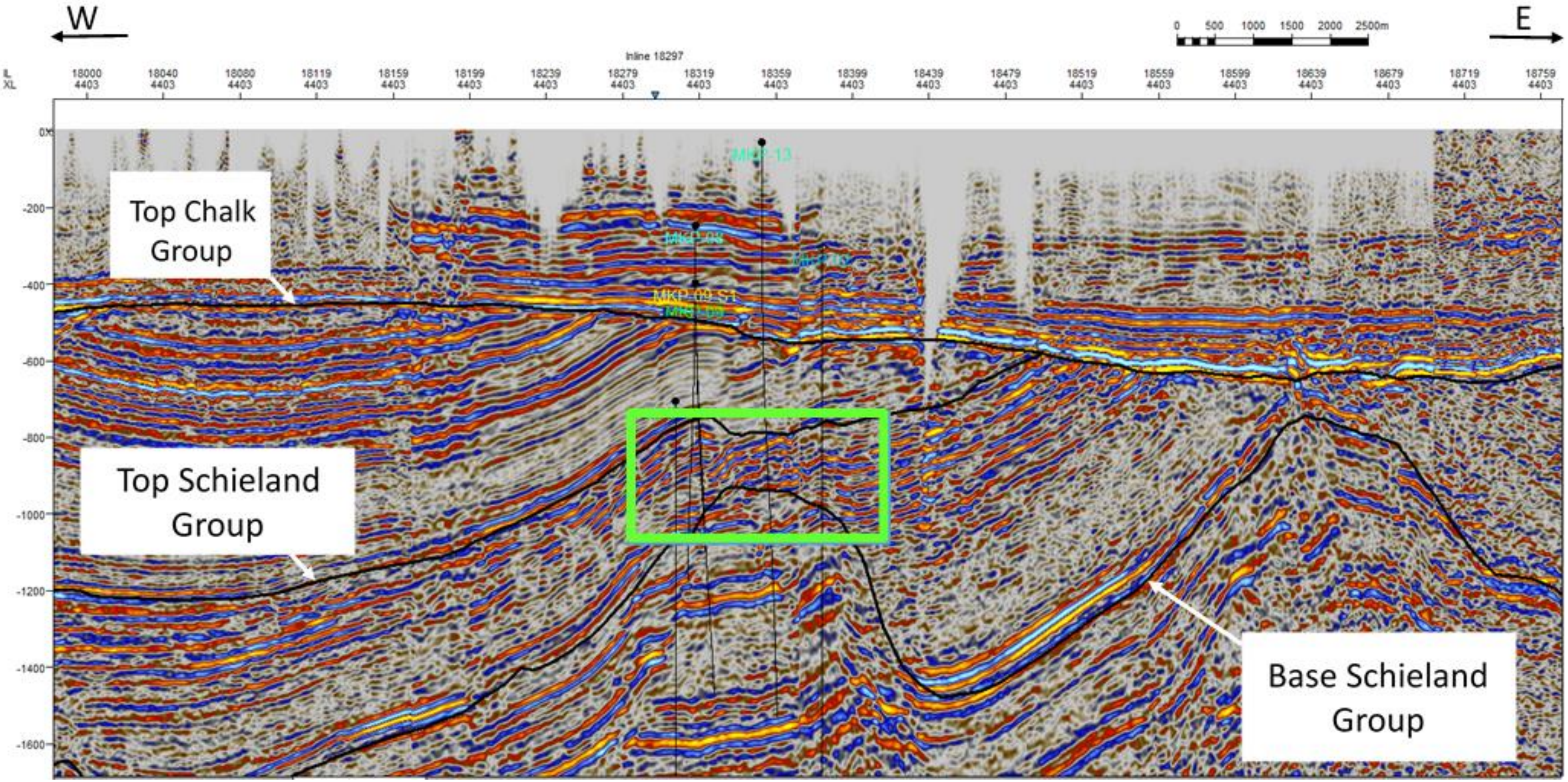


A.1. Reservoir Temperature for scenario B after 30 years. Thermal breakthrough does not occur in the production well (green), for this reason the well spacing was reduced for scenario C and subsequent scenarios. Dimensions in feet



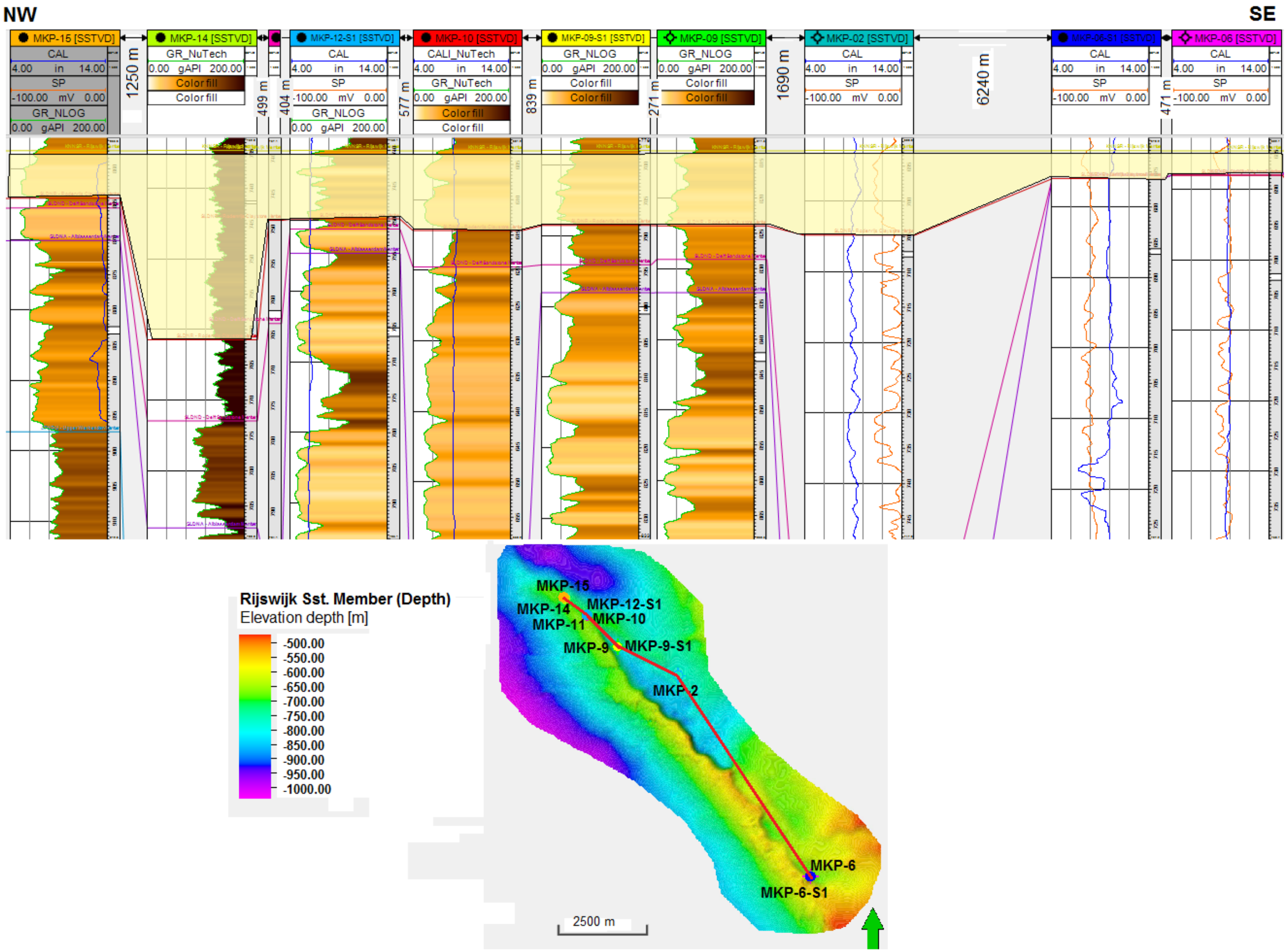
A.2. Reservoir Temperature for scenario D after 30 years. This scenario considers the performance of a single doublet in presence of more wells, even though the presented results are for wells in the middle (blue-injector and orange-producer). Dimensions in feet

Appendix B



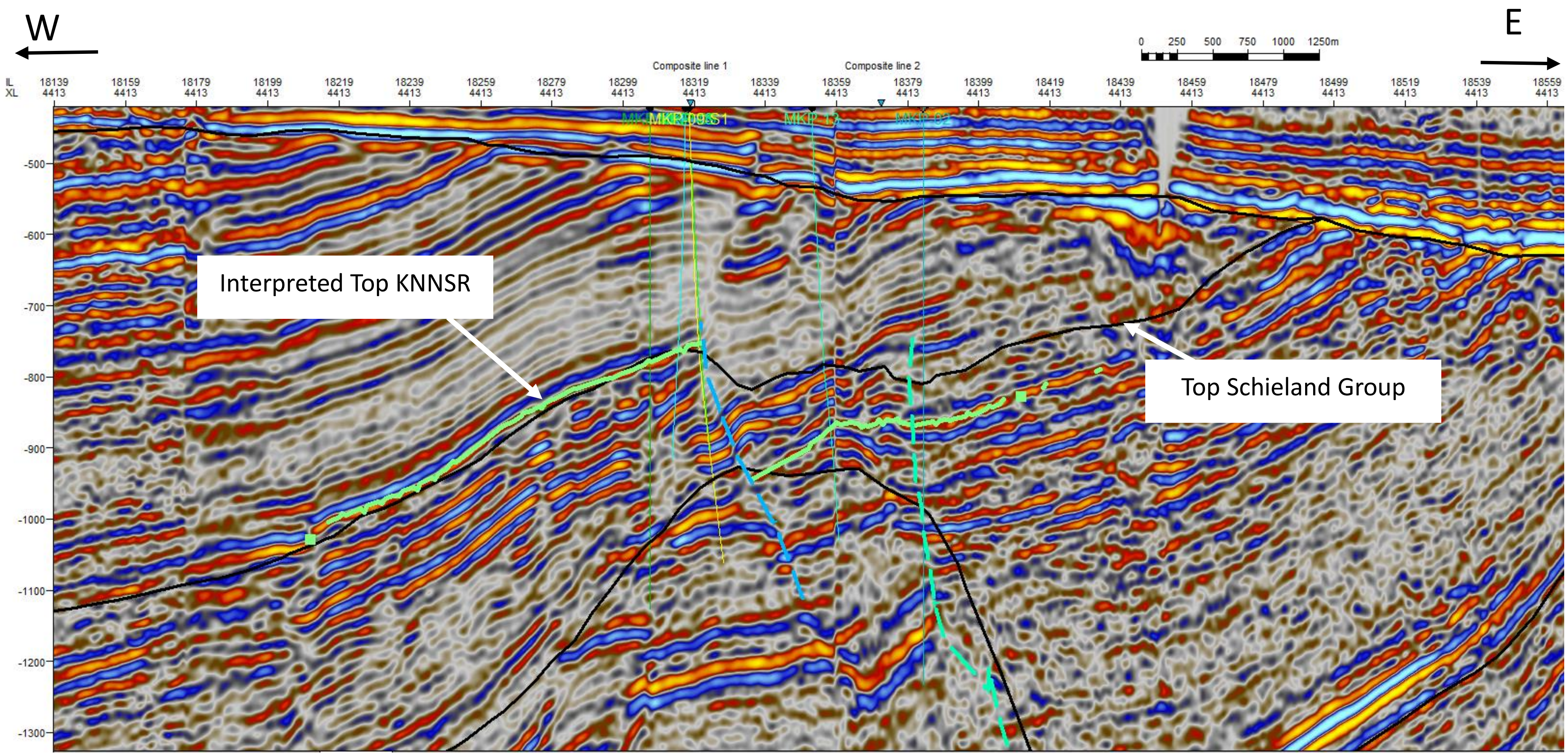
Terracube Onshore Cross-line 4403. W-E cross section in time for the area of the Moerkapelle Field, green square shows the reservoir area. Interpreted surfaces after TNO (2014)

Appendix C



W-E well section for the Moerkapelle Field. Rijswijk Sandstone Member (Highlighted) is the most continuous body along the Field. Notorious differences in thickness due to synsedimentary faulting can be observed

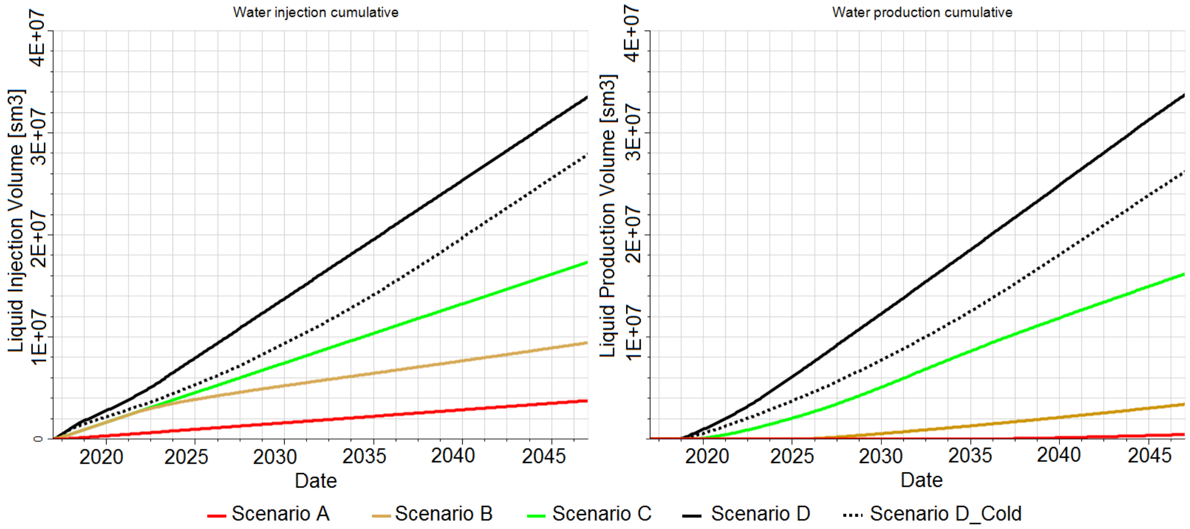
Appendix D



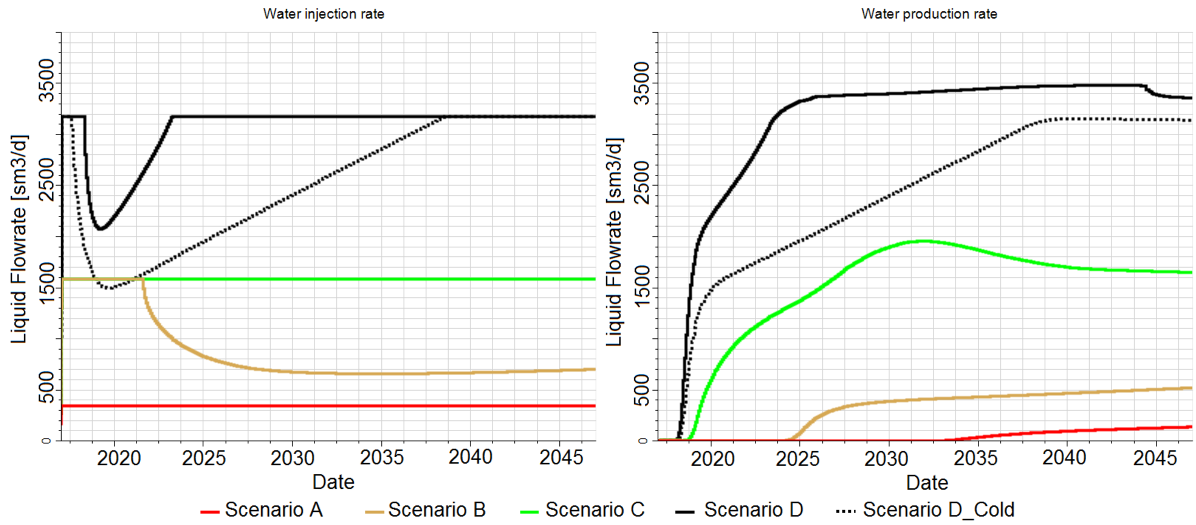
Interpreted Top of the Rijswijk Sandstone Member (KNNSR). The reservoir is bounded by two major faults, eastern fault exhibits a minor displacement. Top Schieland Group after TNO (2014)

Appendix E

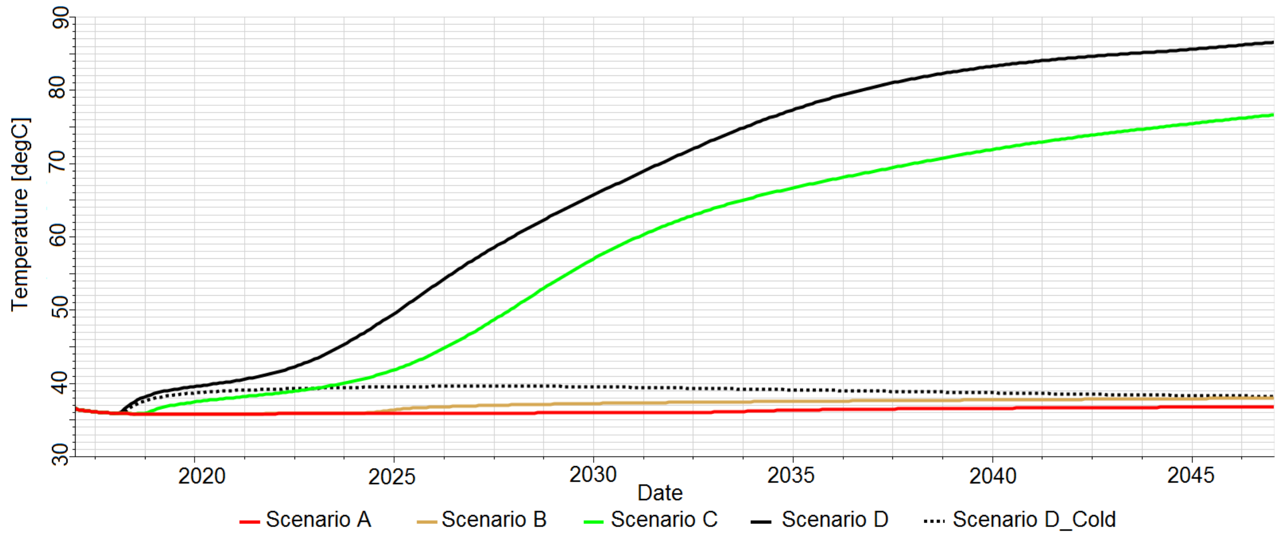
Homogeneous Box Model simulation results. Description of scenarios can be found in Table 3.



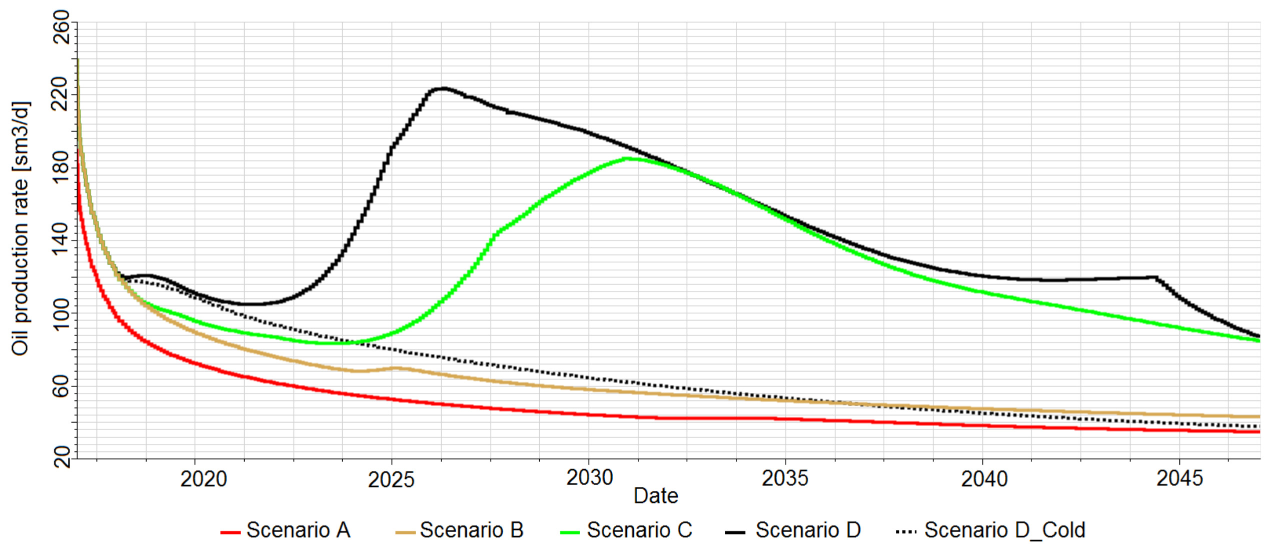
E.1. Cumulative water injection and production. The amount of injected water for scenario D is considerable, but plausible taking into account it is obtained from the geothermal reservoir. High volumes of produced water are used to produce heat on surface



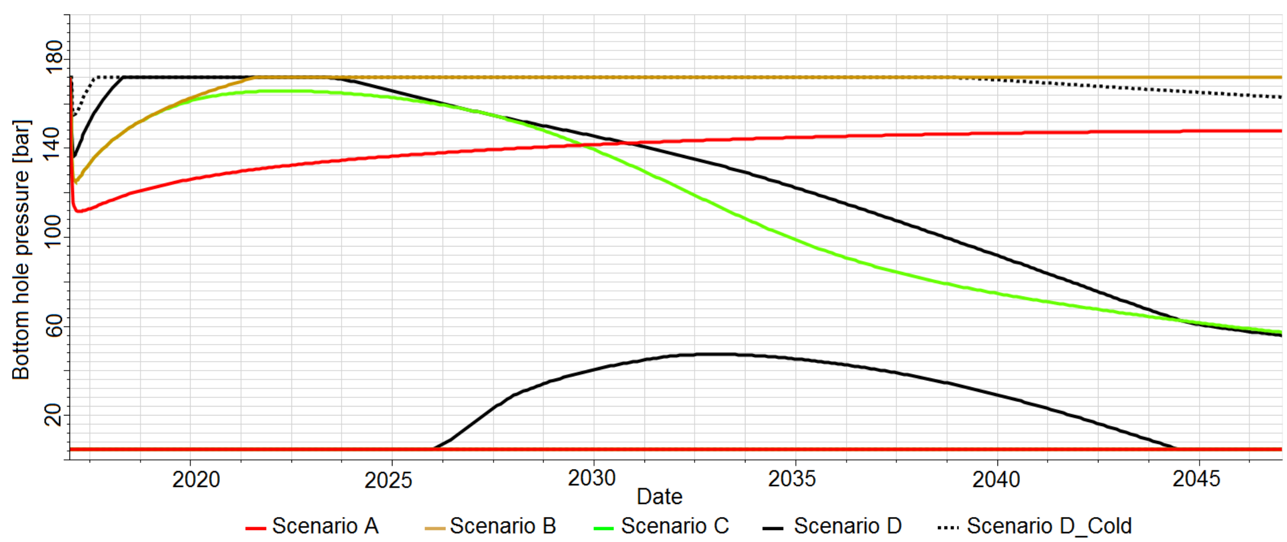
E.2. Water injection and production rates. The amount of water injected for scenario D corresponds to rates obtained from the geothermal well, except for the first 7 years in which extra produced geothermal water can be used to produce heat on surface



E.3. Fluid production temperature (production well). Approximately 10 years from the start of production the produced fluids (mainly water) could be used to generate heat for scenario D



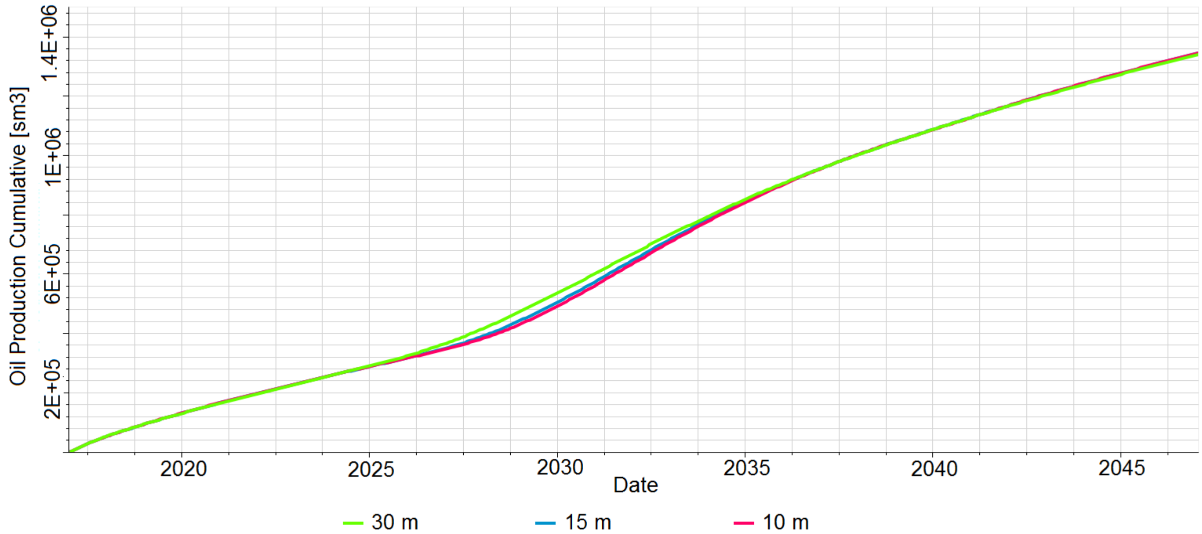
E.4 Oil production rates. High rates occur after water breakthrough



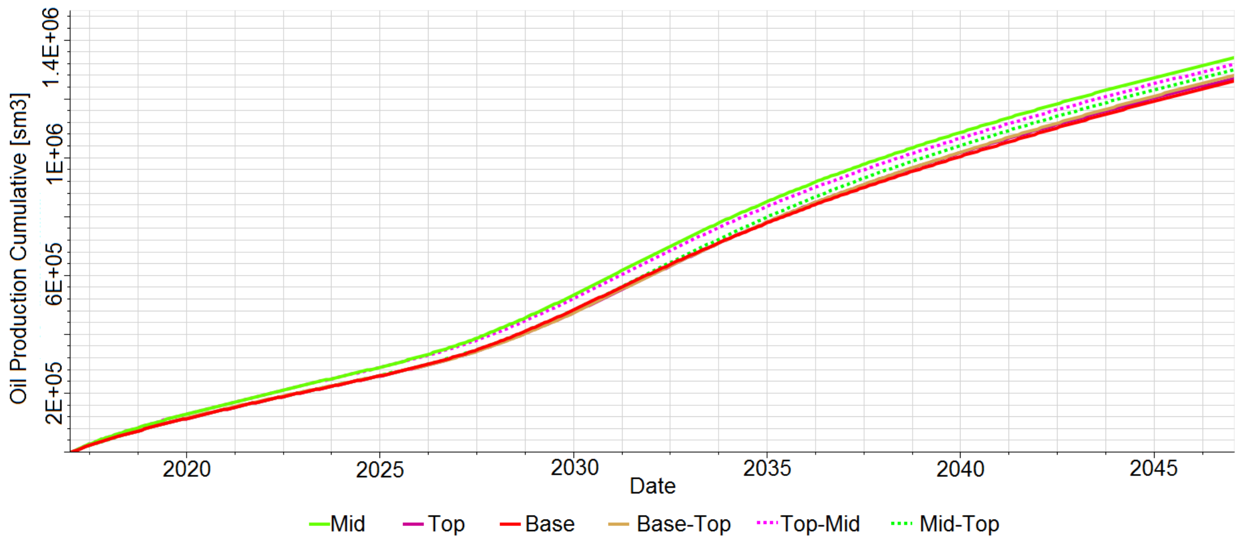
E.5. Well bottom hole pressures. High values correspond to injector wells whereas low values belong to production wells. Missing lines coincide with production pressure boundary condition (5.2 bar)

Appendix F

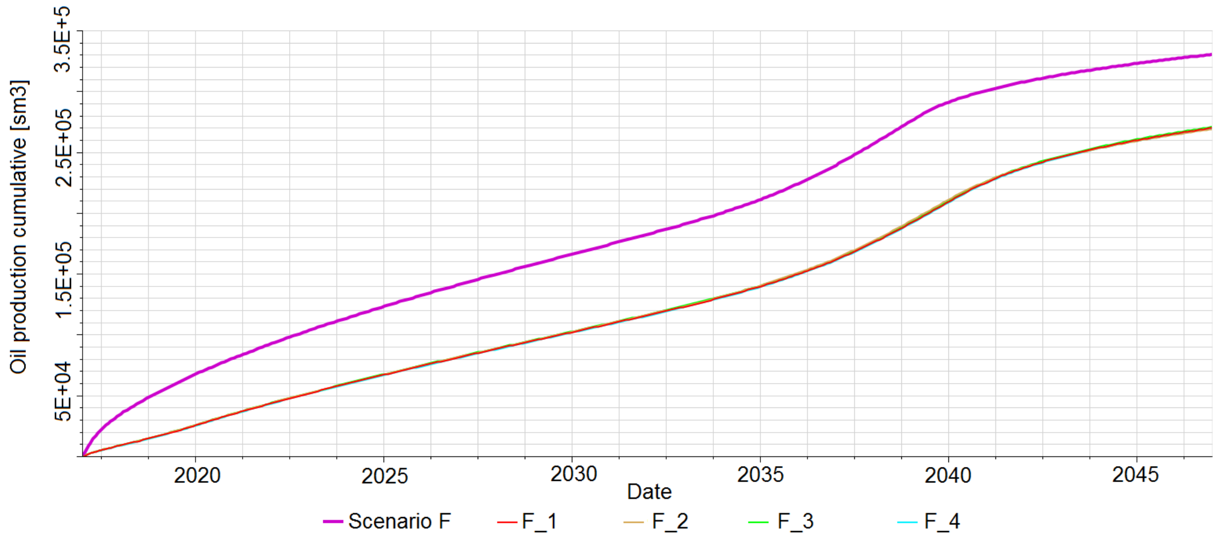
Sensitivity Analysis (*Stages 1 & 2*)



F.1. Cumulative Oil Production for different grid sizes on the Homogeneous Box Model (Scenario C). Differences between 10 m and 15 m grid are very subtle, meaning the results on the 15 m grid are numerically-accurate for a practical case



F.2. Cumulative Oil Production for different well placement within the reservoir on the Homogeneous Box Model. Mid: Injector & producer in the mid-reservoir. Top: Both wells at top cell of the reservoir. Base: Both wells at bottom cell of the reservoir. Base-Top, Top-Mid, Mid-Top: First word refers to injection well and second word to producer



F.3. Cumulative Oil Production for different rock compressibility on the Homogeneous Simple Reservoir Model. Compressibility parameters summarized in **F4**

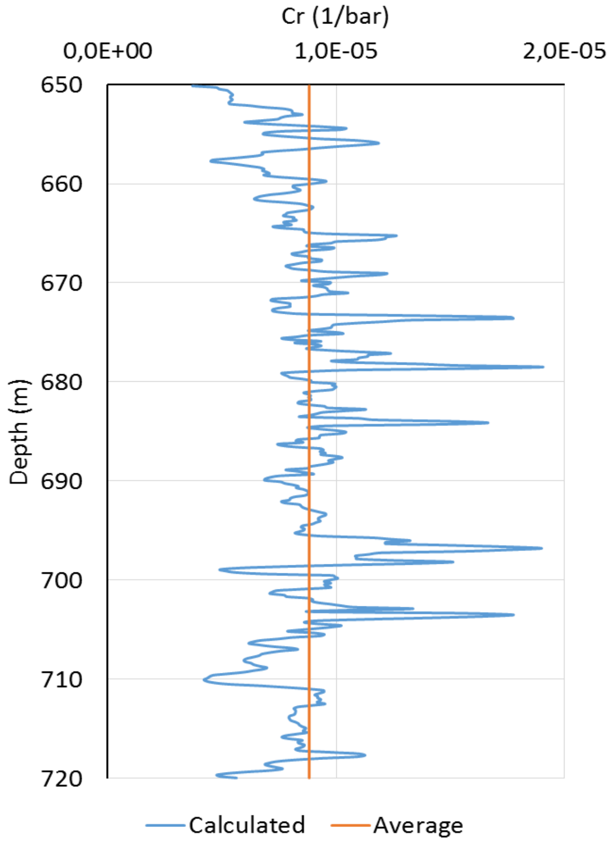
Case	Compressibility (1/bar)	Reference Pressure (bar)	Obtained from
Scenario F	$7.250\,x\,10^{-3}$	89.6	ZiabakhshGanji *et al.* (2016)
F_1	$2.038\,x\,10^{-5}$	89.6	Petrel preset at reservoir pressure
F_2	$4.023\,x\,10^{-5}$	400	Petrel preset at overburden pressure
F_3	$4.023\,x\,10^{-5}$	89.6	Petrel preset at overburden pressure with reservoir pressure as reference
F_4	$8.819\,x\,10^{-6}$	89.6	Average for well MKP-10 (**F.6**)

F.4. Parameters used in the sensitivity analysis for the Homogeneous Simple Reservoir Model (F.3)

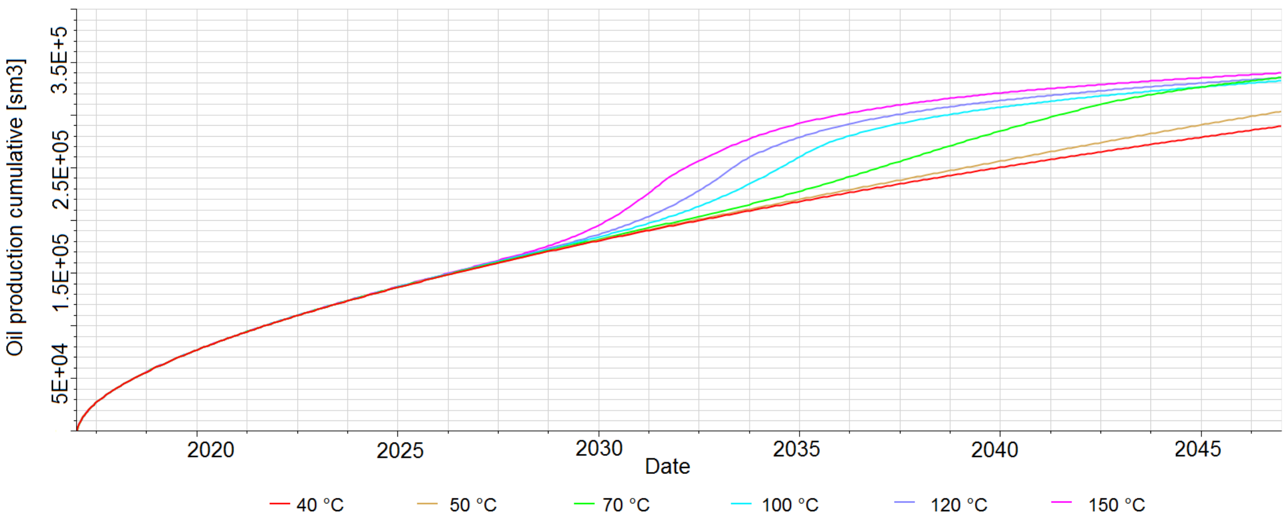
$$M = \frac{1}{C_r} = \rho {V_p}^2 - \frac{K_{fl}}{\emptyset} = \rho {V_p}^2 - \frac{1}{C_{fl}\emptyset}$$

$$C_r = \frac{1}{\rho {V_p}^2 - \frac{1}{C_{fl}\emptyset}} * \left(\frac{1000Pa}{1\ bar}\right)$$

F.5. Confined Modulus in a "weak frame" assumption. Usually used for high porosity, weak sandstones. M: Confined Modulus; C_r: Rock compressibility; ρ: Rock density; V_p: Acoustic sonic log velocity; K_{fl}: Fluid modulus; C_{fl}: Fluid compressibility (Assumed to be heavy oil, calculated for Moerkapelle field: 7.3x10^{-7} 1/bar) . After Hettema & de Pater (1998)



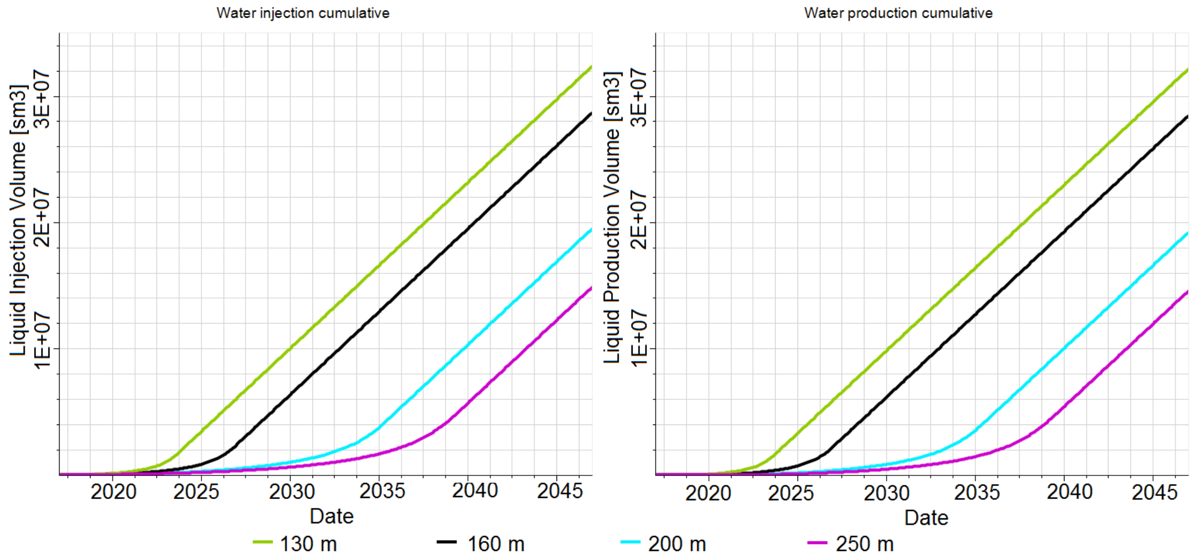
F.6. Calculated rock compressibility in well MKP-10



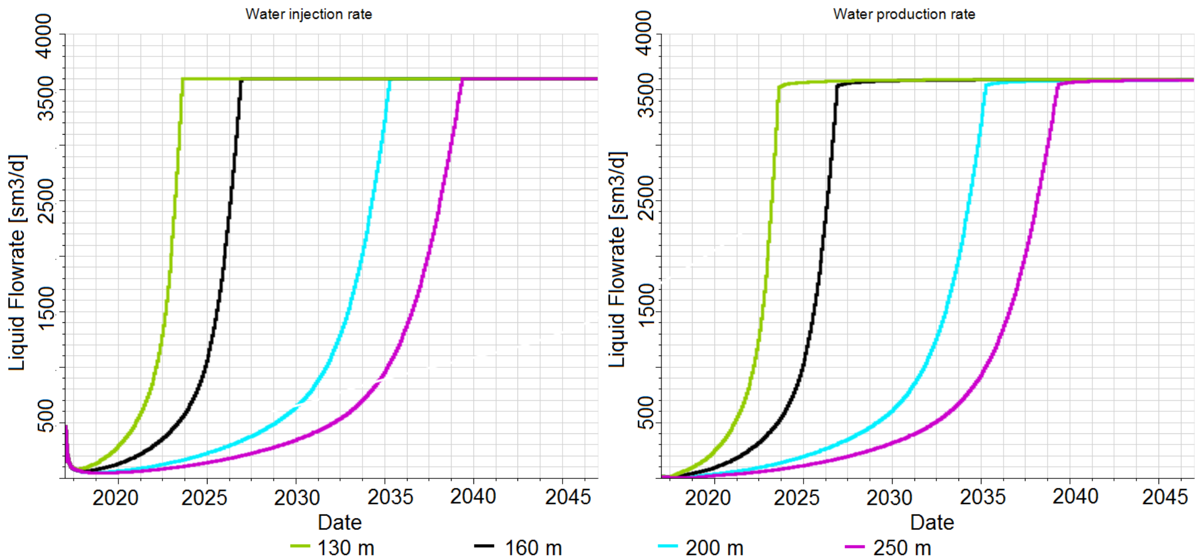
F.7. Cumulative Oil Production for different injection temperatures on the Homogeneous Simple Reservoir Model (scenario F)

Appendix G

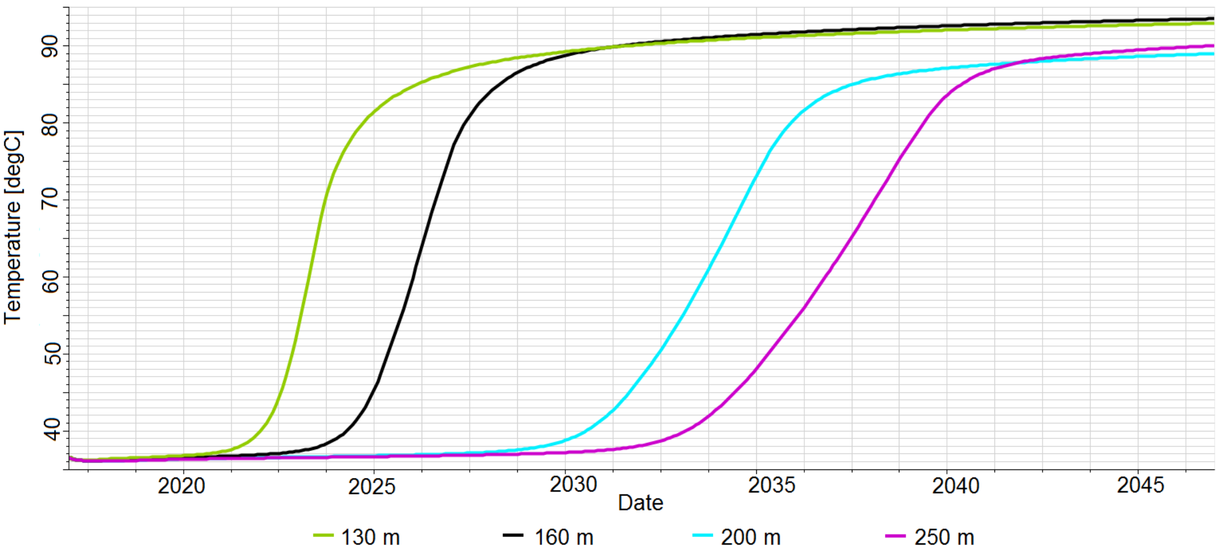
Homogeneous Simple Reservoir Model – Scenario F simulation results for different well spacing



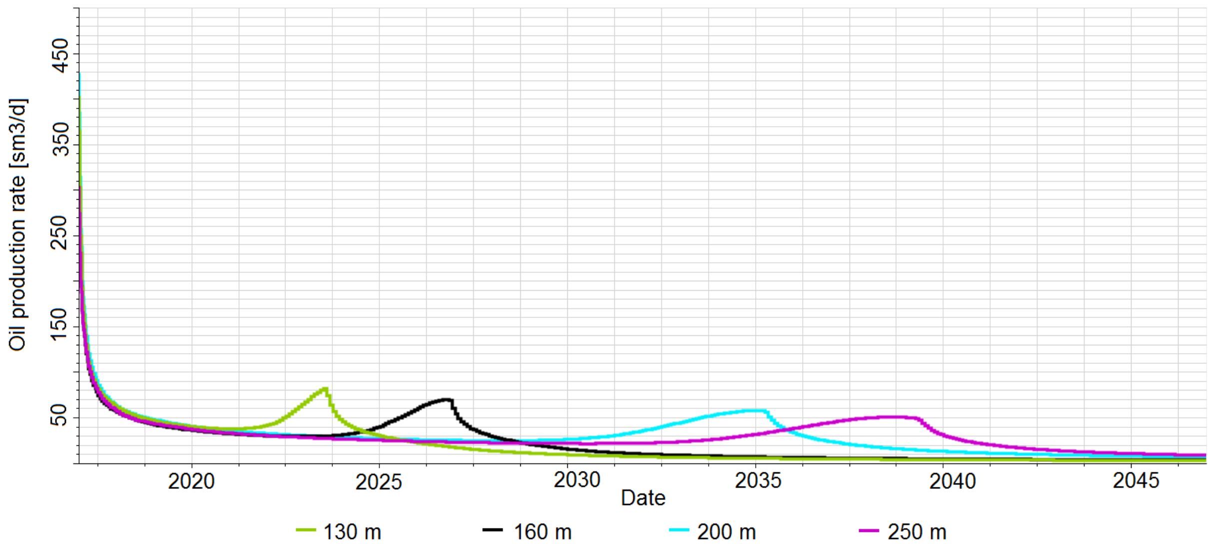
G.1. Cumulative water injection and production for different well spacing



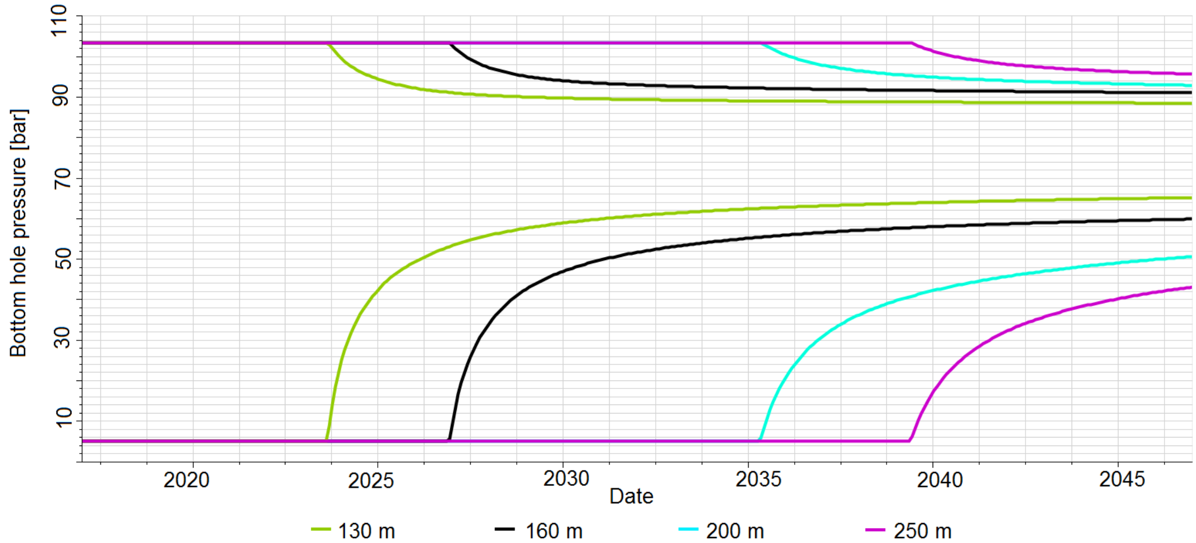
G.2. Water injection and production rates for different well spacing



G.3. Fluid production temperature (production well) for different well spacing



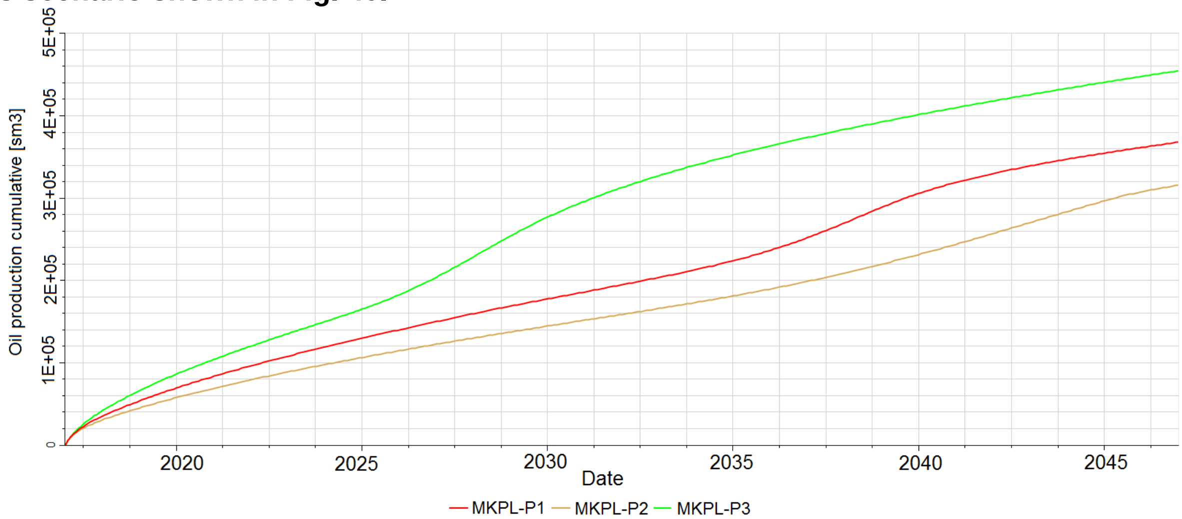
G.4 Oil production rates for different well spacing.



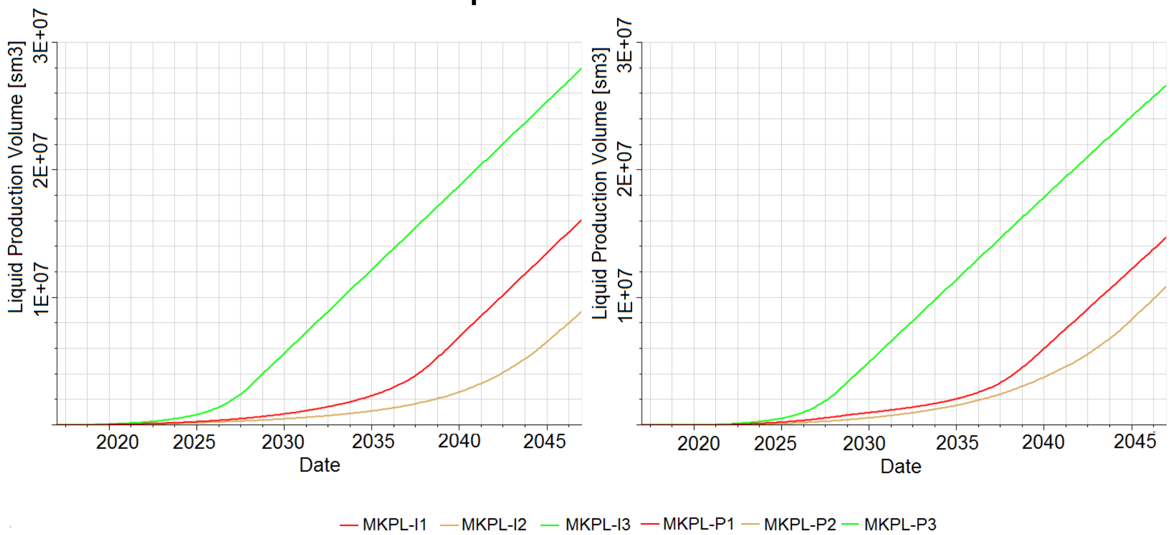
G.5. Well bottom hole pressures for different well spacing. High values correspond to injector wells whereas low values belong to production wells.

Appendix H

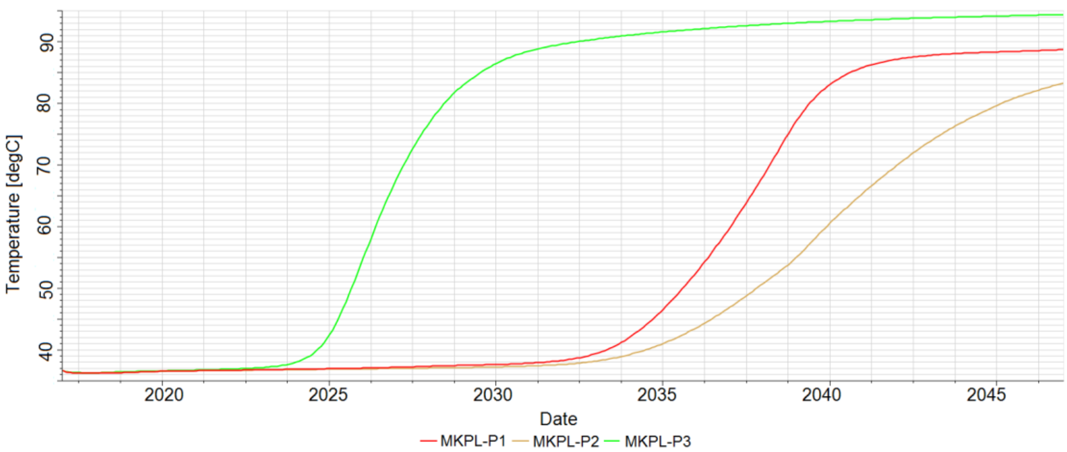
Homogeneous Simple Reservoir Model – Scenario F, individual performance of wells in the 3 doublets scenario shown in Fig. 40.



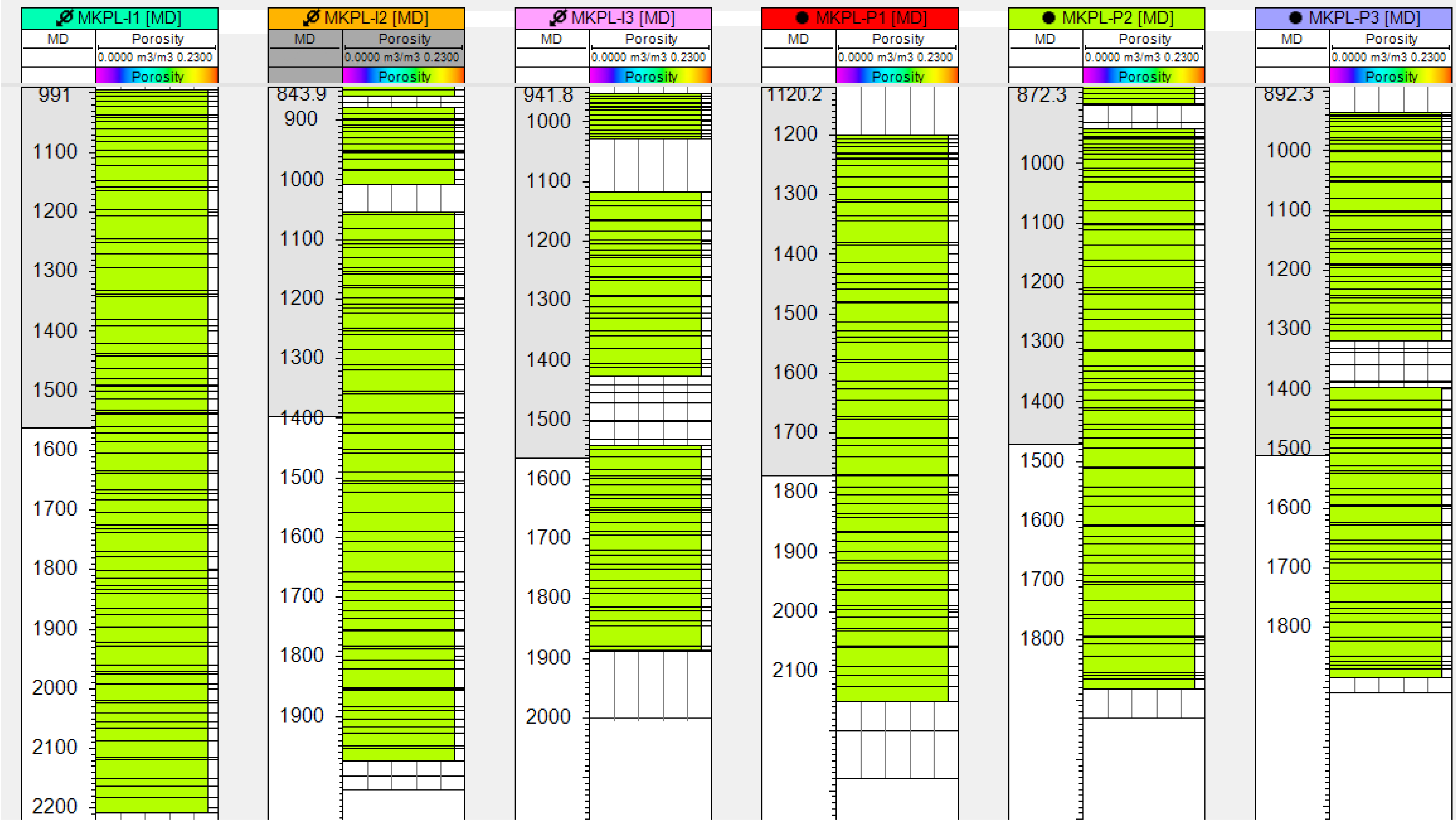
H.1. Cumulative oil production for different wells in the 3 doublets scenario for the Homogeneous Simple Reservoir Model



H.2. Cumulative water injection and production for different wells in the 3 doublets scenario for the Homogeneous Simple Reservoir Model



H.3. Fluid production temperature (production well) for different wells in the 3 doublets scenario for the Homogeneous Simple Reservoir Model



H.4. Reservoir penetration on wells for the 3 doublets scenario on the Homogeneous Simple Reservoir Model. Well productivity illustrated on **H.1.** appears not to be related with the well penetration within the reservoir