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Defining Heat in Place for the Discovered Geothermal Brine Reservoirs in the Croatian Part of Pannonian Basin

Martina Tuschl [1] and Tomislav Kurevija [2,*]

[1] Croatian Hydrocarbon Agency, 10000 Zagreb, Croatia; martina.tuschl@azu.hr
[2] Faculty of Mining, Geology and Petroleum Engineering, University of Zagreb, 10000 Zagreb, Croatia
* Correspondence: tkurevi@rgn.hr

Abstract: One of the important sources of renewable energy is geothermal heat. Its special feature of being independent 24/7 ensures the stability and security of the system, either for electricity or heat production. Geothermal energy has a local character and is limited by the geological characteristics of each state. In the Republic of Croatia, the development of geothermal energy is closely related to the development of the oil industry, as geothermal deposits were discovered during oil and gas exploration. Considering the established temperature gradients in Croatia, there is a greater possibility of using geothermal energy, and for this, it is necessary to evaluate its full potential and possibilities of use. The aim of this research is to determine the heat potential of the Croatian part of the Pannonian Basin System (CPBS), a part of Croatia with exceptional geothermal potential, based on the analysis of a large amount of well data with confirmed water inflow. In order to estimate the heat in place, the available data on the presence of inflow, temperature, and porosity, as well as permeability and volume for each well/reservoir included in the assessment, were considered. In geothermal reservoirs, one of the most important pieces of data besides petrophysical and thermodynamic data is the potential of the well, i.e., the maximum flow under certain permeability and porosity conditions. To define this, the productivity index was made dependent on the permeability of each well, and the inflow in each well was risked using Monte Carlo for three main geological phases in CPBS, which subsequently influenced inflow and spacing between production and injection wells. The beta-PERT distribution for permeability is used in Monte Carlo simulation to determine the most likely values and produce a distribution that resembles the real probability distribution. As a result, geothermal potential was mapped according to the obtained values of heat in place for part of the CPBS covered with analysed wells.

Keywords: geothermal energy; brine; geothermal reservoir; heat in place

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1. Introduction

The greatest incentive for the intensive use of renewable energy sources was created by the Paris Agreement. To implement the goals of the Paris Agreement, the European Commission presented the European Union Green Plan in December 2019. The Green Plan sets out a blueprint to make Europe climate neutral, resource efficient, circular, and competitive by 2050, turning climate and environmental challenges into opportunities for equitable and inclusive change. The targets set require action in several areas, including investing in green technologies and the circular economy, supporting innovation, promoting greener transport, decarbonising the energy sector, ensuring greater energy efficiency in buildings, and making progress towards zero pollution while preserving and restoring ecosystems and biodiversity [1]. An important determinant of the Green Plan is the commitment to promote green budgetary practises in the European Union. The Commission has estimated that the current 2030 climate and energy targets will require a continuous annual investment of 1.5% of BP starting in 2018, or EUR 260 billion per year. Given the crisis caused by the COVID-19 pandemic in 2020, the Commission concluded that this could be an important opportunity in the global response to climate change. The Commission continued to support the green energy transition through grants [2]. The current energy crisis, triggered by Russian aggression against Ukraine, has confirmed the need for EU energy independence and a maximum shift towards renewable energy sources. In order to achieve the goal of energy independence while implementing a low-carbon strategy, substantial investment in renewable energy sources is required, both by increasing the number of renewable energy sources and by improving the technology related to the application of renewable energy sources. One of the most important sources of renewable energy is geothermal energy. Its special feature of being independent 24/7 ensures the stability and security of the system. Geothermal energy has a local character and is limited by the geological characteristics of each state. In the Republic of Croatia, the development of geothermal energy is related to the development of the oil industry, as geothermal deposits were discovered during oil and gas exploration. Indeed, oil production in Croatia goes back a long way in history. The first records of the use of oil in Croatia date back to the middle of the XVI century, when it was used for medicinal purposes, while the first records of deep oil extraction date back to 1933, when the first Gojlo oil well was drilled and extraction began in 1941 [3]. They were mainly used for balneological purposes. In 2018, the first organic Rankine cycle (ORC) geothermal power plant was commissioned in Velika Ciglena with a net capacity of 16.5 MW (megawatt) [4]. Currently, there are 7 geothermal fields and 14 exploration blocks in Croatia, which are expected to yield results that will lead to the use of geothermal water, from heating to electricity generation.

Geothermal Exploration and Production in Croatia

The Republic of Croatia is geologically and geographically divided into the Dinarides and the Pannonian Basin. The geothermal potential of Croatia is located in the Pannonian Basin, which covers almost the entire continental part of Croatia, with an average geothermal gradient of 0.049 °C/m and a heat flow of 76 mW/m^2, while the Dinarides has a geothermal gradient of about 0.018 °C/m with a heat flow of 29 mW/m^2 and therefore has no significant geothermal potential [5–7]. Macenić in 2020 presented a new temperature map that enables the estimation of temperature based on DST measurements [8]. Considering the established temperature gradients in Croatia, there is a greater possibility of using geothermal energy, and for this, it is necessary to evaluate its full potential and possibilities of use. The aim of this research is to determine the heat potential of the Croatian part of the Pannonian Basin System (CPBS) as a part of Croatia with exceptional geothermal potential based on well data with confirmed water inflow. So far, estimates have been made for individual areas and analyses of the temperature, and, accordingly, the geothermal gradient, while an estimate of the heat potential of the entire area has not yet been made. Taking into account the large amount of data available in the CPBS, a potential analysis was carried out. At the time when there was intensive drilling for oil and gas in Croatia, almost 4000 wells were drilled. Currently, there are 500 wells outside the existing production fields. These wells were analysed to determine Croatia's geothermal potential.

2. Methods

With the development of the oil industry, the need arose for uniform terminology and classification to avoid confusion over different interpretations. McKelvey [9] laid the foundation for the classification of reserves and resources with a diagram that eventually became the basis for the generally accepted classification of oil and gas by the Petroleum Reserves and Resources System (PRMS) and that was also accepted as the classification for geothermal waters, making the distinction between resources and reserves. With the development of geothermal potential, there is a need for a methodology suitable for the assessment of geothermal resources in the early stages of exploration [10]. The United Nations Framework Classification [11] has classified fossil energy and mineral resources, which include geothermal waters. Rybach 2015 [12] has developed five categories by which we can categorise geothermal potential—theoretical, technical, economic, sustainable, and developable potential.

Heat in place is used as a standard method for estimating geothermal resources. The method was first proposed by Muffler and Cataldi [13,14] and implemented by the United States Geological Survey (USGS) and is widely used to estimate geothermal potential [15] from the USA to the Netherlands [16,17] and to estimate the potential of individual geothermal fields in the research phase when sufficient data are not available.

In contrast to the geological resource assessment, the heat recovery assessment was later revised by several authors [18–22], resulting in the use of a combination of the Monte Carlo method and the USGS method for a geothermal potential assessment. The Monte Carlo simulation uses multiple trials to determine the value of a random variable. The probability distribution of the input variables produces an estimate of the overall uncertainty in predicting the final calculation [23]. However, in some cases, this can lead to an overestimation of the potential, and a modification of the method is suggested when it comes to recoverable potential [19]. The overestimation of geothermal potential and, in particular, geothermal energy recovery can be misleading when planning future power plants and optimising geothermal field development [24,25], so the sensitivity of the parameters used must be taken into account [26]. The use of Monte Carlo is common in the assessment of oil and gas reserves in the exploration phase, and it has also been applied in the assessment of geothermal potential [27,28]. The use of Monte Carlo models in the assessment of potential provides us with a set of values and the probability of a single event, reducing the risk of the assessment itself [29–32].

Total volumetric heat is considered the energy contained in the solid phase and energy in the pores, i.e., water. In order to calculate the heat contained in rock and heat contained in water separately, the following expression is used:

$$H_i = H_r + H_w = (\Phi \rho_w c_w)(V_i)(T_i - T_0) + (1 - \Phi)(\rho_r c_r)(V_i)(T_i - T_0) \tag{1}$$

where H_i is the total volumetric heat of rock and water (J), H_r is the total volumetric heat contained in rock (J), H_w is the total volumetric heat contained in water (J), ϕ is reservoir porosity, $\rho_w c_w$ is water heat capacity (kJ/m^3/°C), $\rho_r c_r$ is rock heat capacity (kJ/m^3/°C), V_i is the volume of the rock and water (m^3), T_i is the initial temperature of the reservoir (°C), and T_0 is the output temperature of the water (°C).

The estimation of geothermal potential is most accurately performed with numerical simulators and has been the most reliable tool for estimating resources, in addition to the heat-in-place method [33], but estimating a large area, as is the case with estimating the geothermal potential of a region or country, requires an analytical approach, not a numerical one [34,35].

In order to estimate the heat in place, the available data on the presence of inflow, temperature, and porosity as well as the permeability and volume of each well included in the assessment should be considered. Furthermore, it was necessary to determine the volume of each well based on the available data and thus to determine the heat in place in relation to the volume included in the assessment of the heat potential. To determine the volume, in addition to the available data on the thickness of the existing reservoir, Gringarten's setting on the required distance between production and injection wells was used so as not to lower the temperature by using geothermal water [36,37].

2.1. Gringarten Method

Gringarten [36,37] set up an analytical solution to describe the behaviour of the reservoir during geothermal water production. The key assumptions are that there is constant pressure at the well head of the production well during production in a given life of the reservoir, that the reservoir is horizontal and uniform in thickness and located between confined layers, and that heat transfer from surrounding reservoirs or heat conduction from surrounding reservoirs is neglected. In addition, Gringarten assumes that the influence of viscosity is neglected for a longer period if the production cycle gives the impression that the water in the injection well is colder than the produced water. Under the given assumptions, the time is described in which the temperature in the reservoir remains constant, i.e., the required distance between the production and injection wells to avoid cooling of the reservoir.

$$D = \left\{ \frac{2q\Delta t}{\left[\left(\Phi + (1-\Phi)\frac{\rho_r c_r}{\rho_w c_w} \right) h + \left((\Phi + (1-\Phi)\frac{\rho_r c_r}{\rho_w c_w})^2 h^2 + 2\frac{K_r \rho_r c_r}{(\rho_w c_w)^2} \Delta t \right)^{1/2} \right]} \right\}^{1/2} \quad (2)$$

$$\frac{\rho_w C_w}{\rho_a C_a} \frac{Q\Delta t}{D^2 h} = \frac{\pi}{3} \cdot (3) \quad (3)$$

where q is the well flow rate (L/s), ϕ is reservoir porosity (%), $\rho_w c_w$ and $\rho_r c_r$ are water and rock heat capacity, respectively (kJ/m^3/°C), K_r is cap rock thermal conductivity (W/m°C), Δt is reservoir lifetime (years), and h is reservoir thickness (m).

The Gringarten analytical model is used in the early phase of the geothermal reservoir assessment and optimisation [38,39] and has shown sufficiently good agreement with the numerical model [35]. When analysing geothermal field development, one of the input assumptions for the positive economic evaluation of the reservoir is the water breakthrough time, i.e., the distance of production and injection wells to support water breakthrough as late as possible [40–42]. In addition to estimating the time of water breakthrough, the distance of the wells, i.e., the utilised volume of the geothermal reservoir, is also important in assessing the economic viability of the project [43].

2.2. Geological Settings of the Study Area

The Pannonian Basin (PB) is a complex system that developed in parallel with the Alpine–Carpathian orogen. It is a predominantly lowland area bounded by the Carpathians, the Dinarides, and the Alps [44]. The Croatian part of the Pannonian Basin System (CPBS) is located at the southwestern margin of the Pannonian Basin and is divided into four main depressions named Sava, Drava, Mura, and Slavonian Sriem [45]. The location of the CPBS within the PB is shown in Figure 1.

In general, there were three main tectonic phases during the development of the CPBS [46–50]. The first phase (Pre-rift phase) is represented by igneous, metamorphic, and sedimentary rocks from the Palaeozoic and Mesozoic. The boundary between the first and the second phase is an unconformity, which is visible in the well logs as the regional marker Pt (Figure 2). Regional markers are identical features that can be identified on electrologues, or more precisely on resistivity curves. They are defined by similar resistivity values that are repeated in wells drilled in the regional area [51]. According to Saftić and Malvić [52], markers are characterised by clear and easily recognisable features in a given area. These characteristics distinguish them from deposits in the upper and lower areas. They are correlative due to their extremely small thickness and large lateral spread. In some cases, they represent an unconformity, mostly between Neogene –Quaternary sediments and older volcanic, metamorphic rocks. The second phase (syn-rift phase) is represented by sedimentation in the lower/middle Miocene that started as a result of the first extensional tectonics. The lithology of the syn-rift phase is very heterogeneous and consists of volcanic and pyroclastic rocks, breccias and conglomerates, sandstones, limestones, calcareous marls, etc. [53]. During the Sarmatian [54], minor compression (early post-rift) occurred, resulting in widespread pre-Pannonian unconformity, visible on well logs as regional marker Rs7 (Figure 2). During the third phase (post-rift phase), Pannonian thermal subsidence generally reopened the depositional space. Turbidite currents were the dominant mechanism for the transport of clastic material [45,55–59]. Sandstones were deposited during periods when turbidite currents were active, and marl was recorded as a typical deep-water sediment during these periods. This sequence is represented by sandstone/marl intercalations (Figure 2). The Pliocene and Pleistocene were periods of basin compression and inversion. Sedimentation continued in residuals of the Pannonian Lake, filling it with marly clays, marls, sands, gravels, and coals [55,58,60].

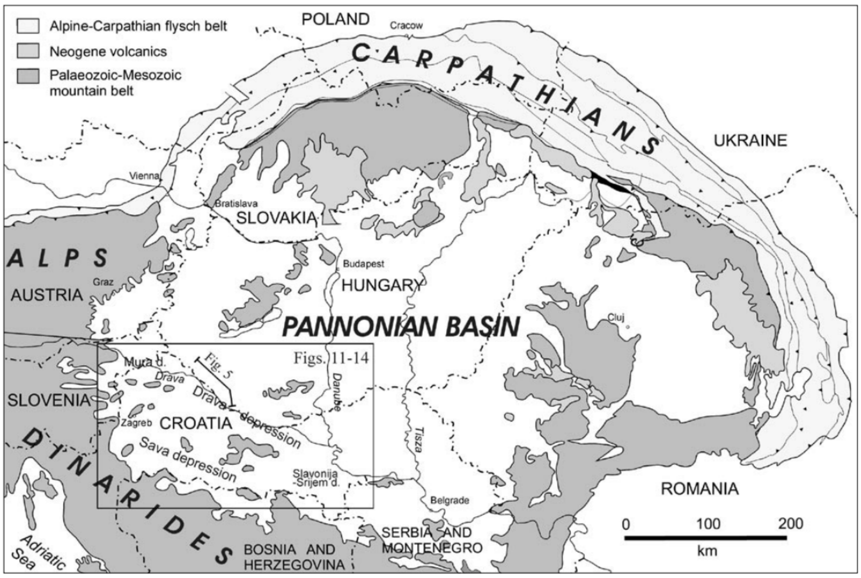


Figure 1. Location of the Croatian part of the Pannonian Basin System within the Pannonian Basin [53].

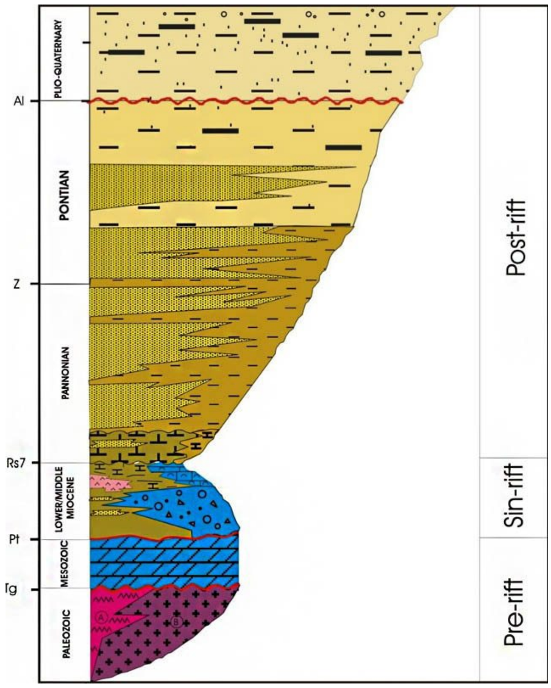


Figure 2. Schematic geological column of the Pannonian basin [53,61].

2.3. Drill Stem Test

To determine the geothermal gradient and thus the geothermal potential, the most important parameter is the static reservoir temperature, frequently indicated as the undisturbed or virgin rock temperature (VRT). During the construction of the well, the bottom hole temperature (BHT) is determined by logging measurements at certain intervals, and the temperature is also measured during the drill steam test (DST) [62]. To determine the temperature of the geothermal reservoir, it is assumed that BHT measurements represent data under uncontrolled conditions, i.e., in situations where the temperature of the wellbore zone is disturbed during the drilling of the well. To use BHT as a reference, a large amount of downhole data is required, which is often not available. Since temperature measurements during DST represent the inflow of fluid into the wellbore, they are considered to be of better quality than BHT measurements [63]. The data from the analysed wells relate to measurements during DST and are considered relevant for a given reservoir. However, further analyses should be carried out regarding the quality of the data obtained, as they were carried out for the purpose of exploring the inflow of oil and gas and no custom measurements were taken at the time of the water inflow.

2.4. Productivity Index

In geothermal reservoirs, one of the most important pieces of data besides temperature is the potential of the well, i.e., the maximum flow under certain permeability and porosity conditions. To define this, the methodology of IPR curves (inflow performance relationship) is used to define the flow in a given reservoir at a given difference between the reservoir pressure and the dynamic pressure at the bottom of the well. The parameter that establishes the relationship between flow and pressure is the productivity index (m^3/day/bar).

$$PI = \frac{q}{\Delta p} \tag{4}$$

where q is the production flow rate at wellhead conditions and Δp is the pressure drop between reservoir pressure and dynamic well pressure. Following assumptions that the flow around the well is radial, is single-phased with an incompressible fluid, has a homogeneous permeability distribution in the formation, and has a single fluid reservoir saturation, the Darcy equation gives us the production of the well:

$$q = \frac{k}{\mu}\frac{A}{L}(p_1 - p_2) \tag{5}$$

For radial flow

$$q = \frac{2\pi kh}{\mu}\frac{(p_e - p_w)}{\ln\left(\frac{r_e}{r_w}\right)} \tag{6}$$

where k is the reservoir permeability, h is the reservoir thickness, μ is the dynamic viscosity of the fluid, p_e is the reservoir pressure, p_w is well flow pressure, r_e is the drainage radius, r_w is the wellbore radius, A is the affected area, and L is length.

Combining the Darcy radial flow equation, the productivity index can be expressed as:

$$PI = \frac{q}{p_e - p_w} = \frac{2\pi kh}{\mu \ln\left(\frac{r_e}{r_w}\right)} \tag{7}$$

3. Results and Discussion

The assessment of heat in place is based on data from wells that were drilled for the purpose of hydrocarbon exploration but turned out to be negative, i.e., water flowed into the reservoir. The presence of water was demonstrated in DST tests for all wells used for the assessment. In this way, the presence of water saturation, the possibility of inflow into the well, and the data on temperatures measured during the tests were proven beyond doubt. Data from 181 wells were used for the assessment, and all wells have a temperature greater than 30 °C, i.e., the lowest temperature used for the assessment is 32.75 °C, while the highest is 213 °C. In cases where water saturation in multiple reservoirs was determined by DST tests on a single well, only data from reservoirs with a higher temperature were used.

With regard to the geological characteristics of the CPBS, the well data were analysed in relation to the affiliation to the Drava or Sava depressions and with regard to the lithology of the deposit in connection with the three main tectonic phases during the development of the CPBS. In this way, the assessment was made for specific deposits of each main tectonic phase and divided into pre-rift, syn-rift, and post-rift phases in terms of specific lithological markers. For the purposes of analysis, the data obtained from the wells in the Mura Depression are linked to the data in the Drava Depression, while the data in the Slavonian Sriem Depression are also linked to the data in the Sava Depression.

In total, data from 181 wells were used for analysis. Of these, 92 wells belong to the Drava Depression area, while 89 wells belong to the Sava Depression. In the Drava Depression, 75.00% of the wells had porosity data, while 81.52% of the wells had permeability data measured during the DST tests. In the Sava Depression, 74.67% of wells had porosity data, while 67.42% of wells had porosity data. Every single tectonic phase analysed separately had more than 60% of porosity and permeability data, except for the pre-rift phase in the Sava Depression, where the proportion of data was less than 60%. The analysed data are listed in Table 1.

Table 1. Data analysed for heat-in-place estimation.

		Drava Depression			Sava Depression		
	Total No. of Wells	**No. of Wells**	**Porosity Data**	**Permeability Data**	**No. of Wells**	**Porosity Data**	**Permeability Data**
Post-rift	51	19	63.16%	68.42%	32	68.75%	78.13%
Sin-rift	96	51	82.35%	84.31%	45	64.44%	62.22%
Pre-rift	34	22	68.18%	86.36%	12	41.67%	58.33%
Total	181	92	75.00%	81.52%	89	74.67%	67.42%

In order to create a heat-in-place assessment model in a geothermal reservoir, well data analysis must determine the volume of the reservoir involved in the assessment. Since the work does not include geological modelling of each volume around the well, Gringarten's method was used to determine the minimum distance between well doubles involved in production. To determine the flow through the observed well, a productivity index was modelled based on the available well data. Based on the available porosity data, the dependence of porosity on the depth of the reservoir was established for each lithological unit and geological depression. Monte Carlo modelling was used to determine permeability, as underestimated values determined by measurements were assumed. The aforementioned assumption was made because the well tests (DST) used for the estimation were conducted to detect oil and gas in the reservoir. The moment there was water intrusion, without encountering hydrocarbons, the tests were usually stopped. For this reason, the data obtained were not quite sufficient to perform a flow analysis through the reservoir. Another reason was the small part of the interval, mainly the upper part of the reservoir, which was the subject of the tests. The analysis of the permeability dependence on porosity also did not provide satisfactory data due to large differences in the depths of the individual lithological units in space, i.e., different depth distributions of the individual lithological units, as the analysis was carried out for the entire CPBS area affected by analysed wells. The distribution of the geothermal gradient calculated at the depths of the reservoir with an average ambient temperature of 11.6 °C [7] also shows the dispersion of the geothermal gradient by lithological unit. A dominant geothermal gradient of 0.04 to 0.05 °C/m is evident in all lithological units, with large variations in any unit with geothermal gradients greater than 0.06 °C/m (Table 2).

Table 2. Geothermal gradient calculated at the depths of the reservoir.

Geothermal Gradient (°C/m)	Post-Rift	Syn-Rift	Pre-Rift
$Tg < 0.04$	35.29%	15.63%	11.76%
$0.04 < Tg < 0.05$	43.14%	46.88%	47.06%
$0.05 < Tg < 0.06$	17.65%	31.25%	32.35%
$Tg > 0.06$	3.92%	6.25%	8.82%

The beta-PERT distribution was used to model the throughput value of permeability. The beta-program evaluation and review technique distribution (beta-PERT distribution) for permeability is used in Monte Carlo simulation to determine the most likely values and produce a distribution that resembles the real probability distribution. The model was built with 50,000 iterations for each well. The beta-PERT distribution emphasises the most likely value over the minimum and maximum estimates and constructs a smooth curve that gradually emphasises the values near the most likely value more in favour of the minimum and maximum values. The modelled permeability was an input parameter for determining the productivity index for each well, and in this way, a correlation between the measured flow values for the wells and the modelled values was achieved (Figures 3–5). After determining the input parameters, the heat in place was modelled, and, in this way, the possible heat around a single well, i.e., a pair of wells, was estimated based on the actual well data (Figure 6). By assessing the risk in the permeability assessment with the Monte Carlo method, the risk of brine inflow in each well was also assessed. In this way, the inflow in each well was risked using Monte Carlo (Figures 7–9) for three main lithological units, which subsequently influenced inflow and spacing between production and injection wells.

To determine the thickness of each individual well area, two main assumptions were made:

- The thickness of the reservoir corresponds to the thickness of the lithological unit.
- The entire deposit participates in the assessment.

To determine the distance between the production and injection wells, the following assumptions were made:

- There has been a constant temperature between the doublet wells over 30 years.
- There is a pressure drop at the wellhead of 20 bar.
- The system consists of a production well and an injection well.

Since the model heat in place is built on the assumption of permeability in such a way that the minimum, maximum, and mean values are determined through Monte Carlo modelling, we can rank the evaluation of heat in place with a certain degree of certainty; in this way, we have obtained the distribution of the dispersion heat in place in the space around the observed wells. Taking into consideration the limited volume that has been analysed, we can talk about the values of the mean heat in place of 5.373×10^{18} J up to maximum values of 2.094×10^{19} J (Table 3) in the area of analysed wells.

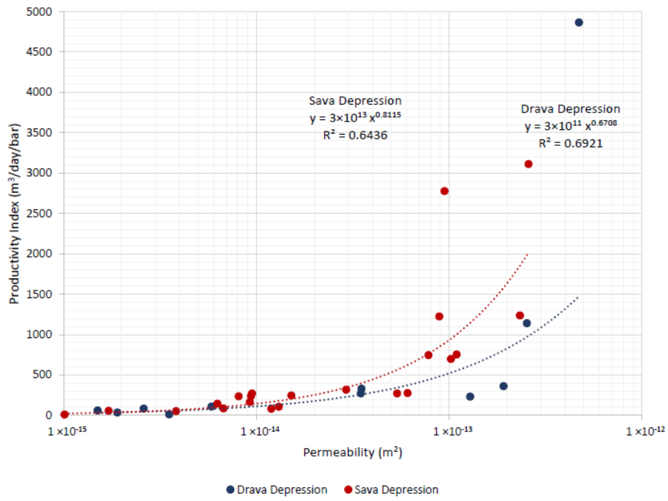


Figure 3. Productivity index vs. permeability data correlation—post-rift phase.

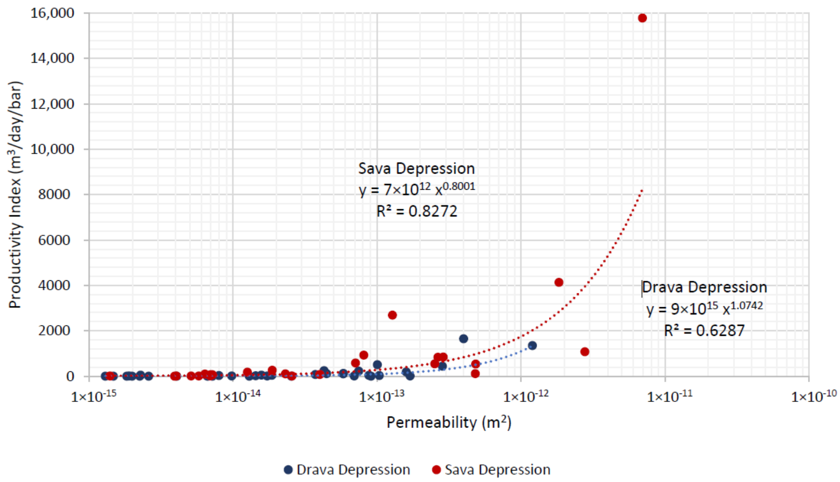


Figure 4. Productivity index vs. permeability data correlation—syn-rift phase.

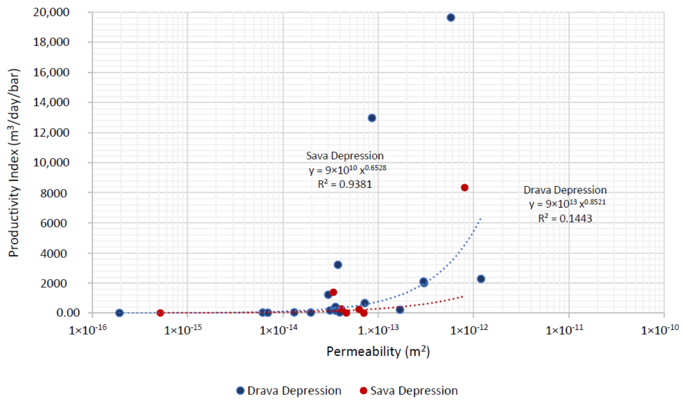


Figure 5. PI vs. Permeability data correlation—pre-rift phase.

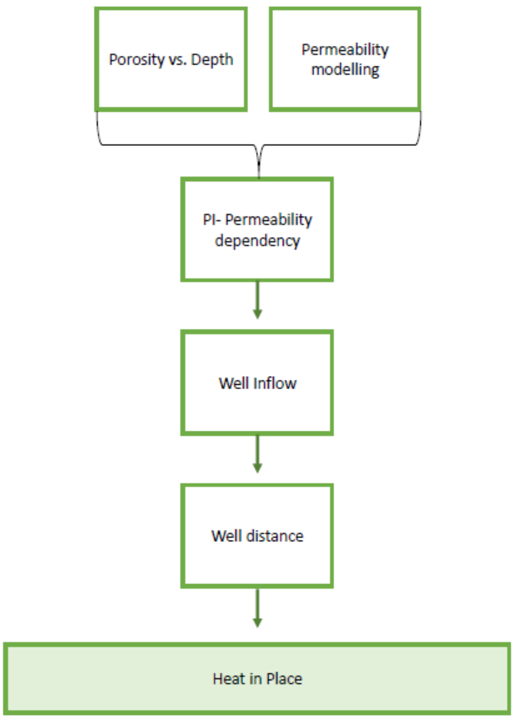


Figure 6. Calculation of heat-in-place flow chart.

For Sava Depression, specific rock density is expressed by the following formula:

$$\rho_S = -0.792e^{-0.725H} + 2.72 \tag{8}$$

while Drava Depression is expressed by the following formula:

$$\rho_D = -0.747e^{-0.809H} + 2.72 \tag{9}$$

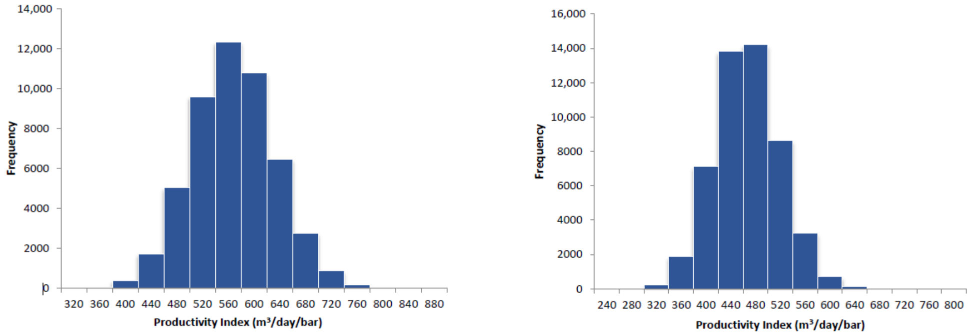
For specific rock heat in Sava depression, this expression is used:

$$c_S = 0.602e^{-1.177H} + 0.898 \tag{10}$$

For Drava depression,

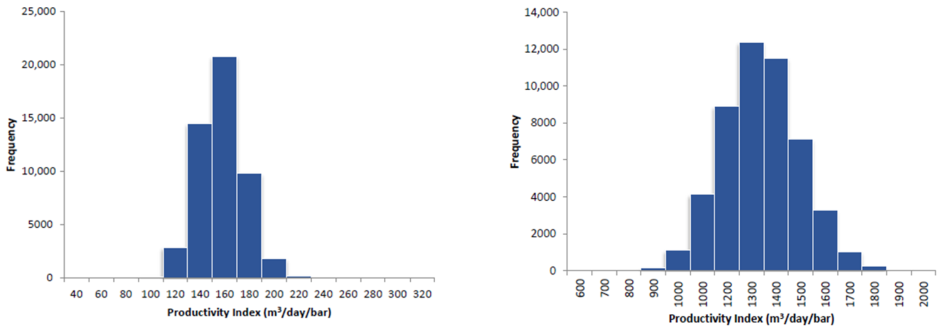
$$c_D = 0.557e^{-1.460H} + 0.908 \tag{11}$$

where H is the depth of reservoir in metres.



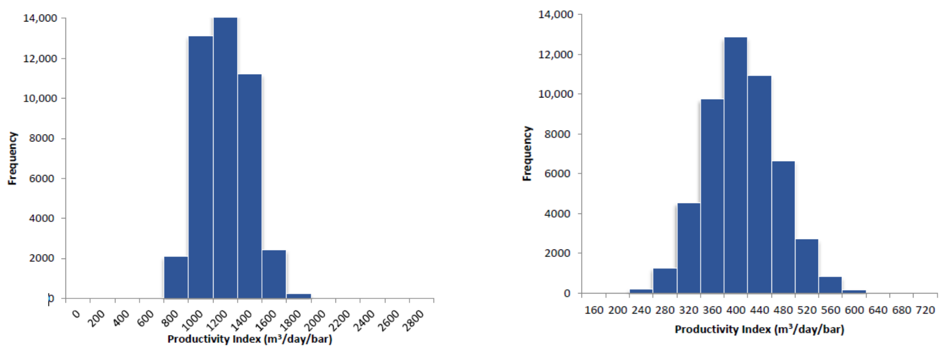
(**a**) (**b**)

Figure 7. Productivity index distribution—Drava (**a**) and Sava (**b**) Depression—post-rift phase.



(**a**) (**b**)

Figure 8. Productivity index distribution—Drava (**a**) and Sava (**b**) Depression—syn-rift phase.



(**a**) (**b**)

Figure 9. Productivity index distribution—Drava (**a**) and Sava (**b**) Depression—pre-rift phase.

Table 3. Heat-in-place probability distribution of analysed well doublets.

	Heat in Place-Analysed Well Doublets (J)		
	Mean	**Minimum**	**Maximum**
Post-rift	7.935×10^{17}	3.620×10^{16}	2.612×10^{18}
Syn-rift	3.101×10^{18}	1.158×10^{16}	1.281×10^{19}
Pre-rift	1.479×10^{18}	9.655×10^{16}	5.521×10^{18}
TOTAL	5.373×10^{18}	1.443×10^{17}	2.094×10^{19}

Since the heat-in-place calculation is carried out for well doublets, and in order to spatially determine the spread of the potentials with the risk distribution, the maps were created in such a way that the heat-in-place values were assigned to the well as point data to which the modelling referred over the area that was modelled as the volume affected with doublet production. The maps were produced using the Kriging method of spatial interpolation. By modelling the heat-in-place values, point data were obtained in relation to the analysed wells, and the data were interpolated to other areas of the CPBS using the geostatistical Kriging method, i.e., to the extent of each lithological unit. Ordinary Kriging was used, which is based on determining the value of the unmeasured points in such a way that a simple linear weighted average of the measured points is applied to the unmeasured points with the smallest possible deviation. In this way, the heat in place is distributed two-dimensionally on site and modelled for a doublet well, and its probability distribution is shown in Figures 10–12 for the individual geological phases.

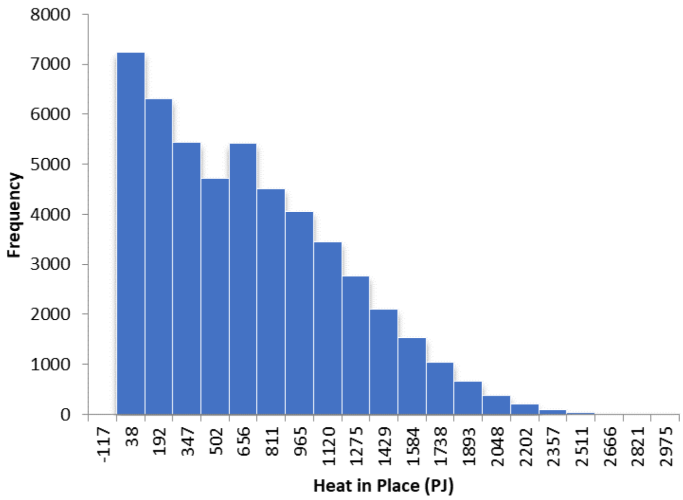


Figure 10. Heat-in-place probability distribution for well doublets—post-rift phase.

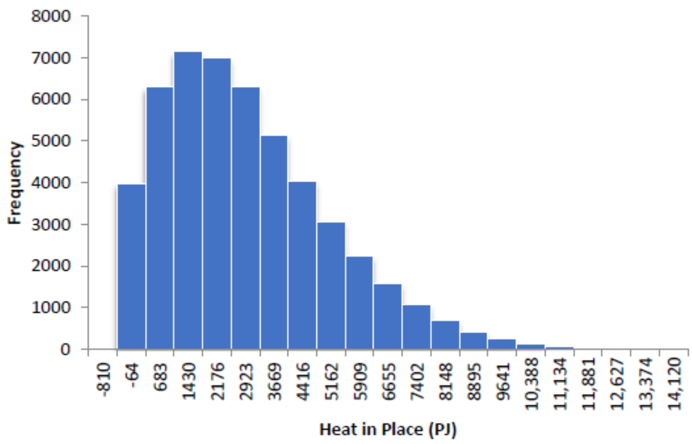


Figure 11. Heat-in-place probability distribution for well doublets—syn-rift phase.

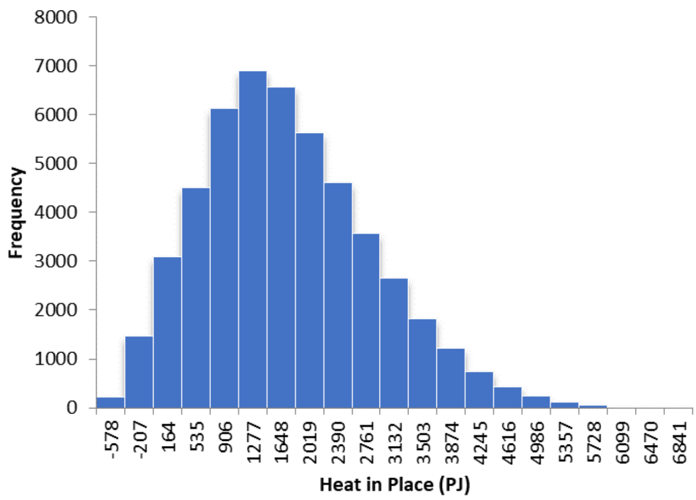


Figure 12. Heat-in-place probability distribution for well doublets—pre-rift phase.

Distribution of the geothermal gradient by lithological units is shown in Figures 13–15.

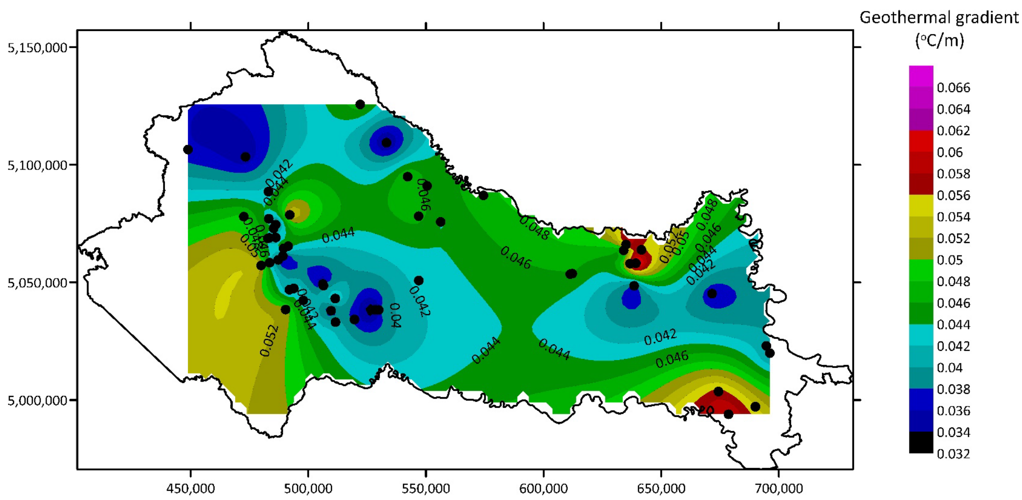


Figure 13. Geothermal gradient map for post-rift phase.

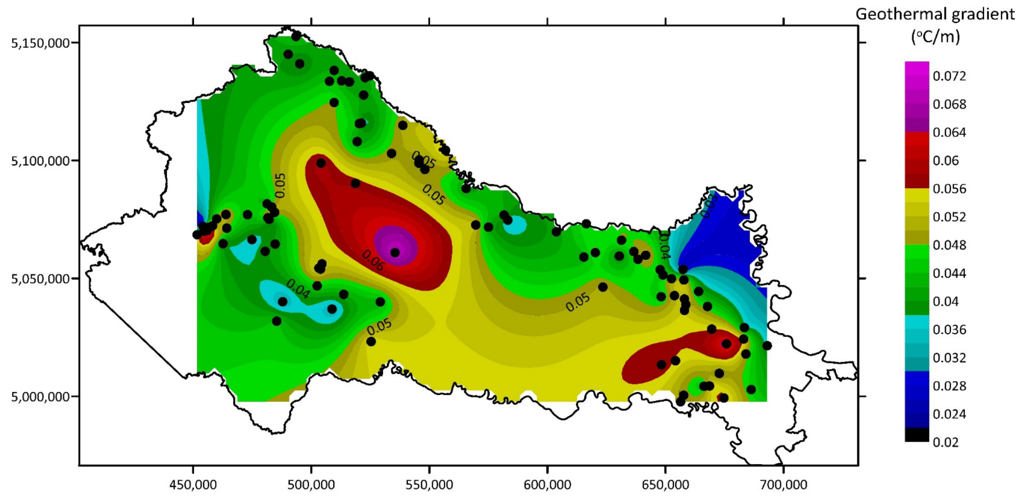


Figure 14. Geothermal gradient map for syn-rift phase.

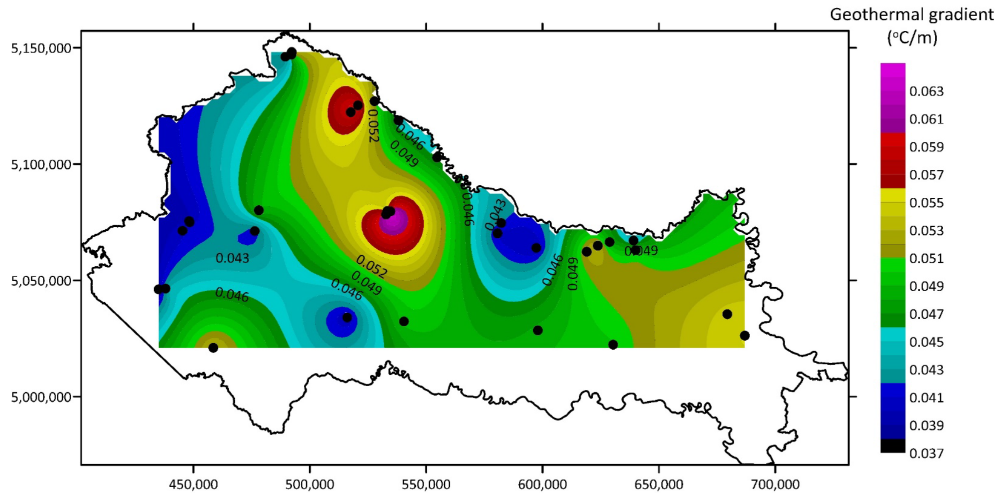


Figure 15. Geothermal gradient map for pre-rift phase.

The spatial distribution of the mean values of the probability distribution of heat in place in the affected doublet area is shown in Figure 16 for the post-rift phase, Figure 17 for the syn-rift phase, and Figure 18 for post-rift phase.

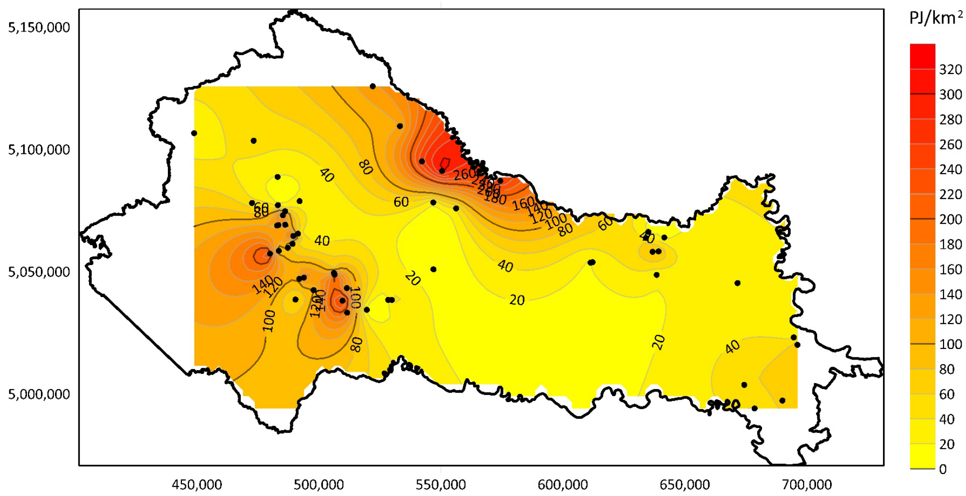


Figure 16. Mean heat-in-place areal distribution—post-rift phase.

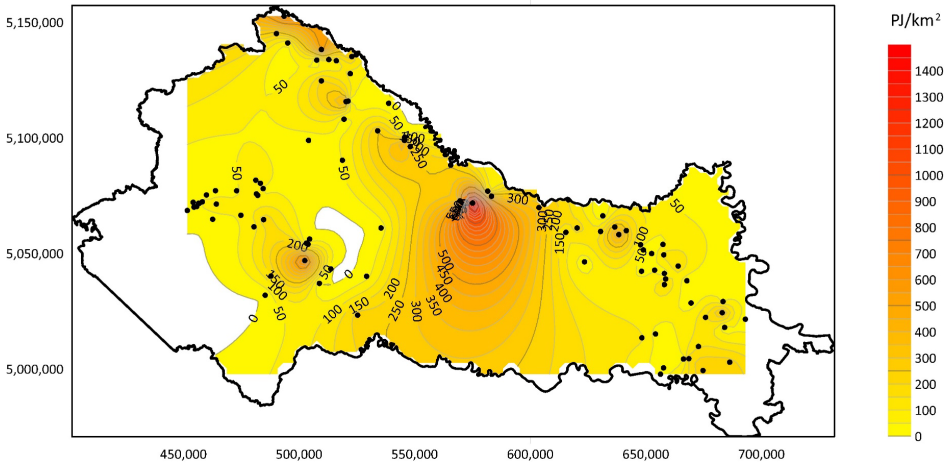


Figure 17. Mean heat-in-place areal distribution—syn-rift phase.

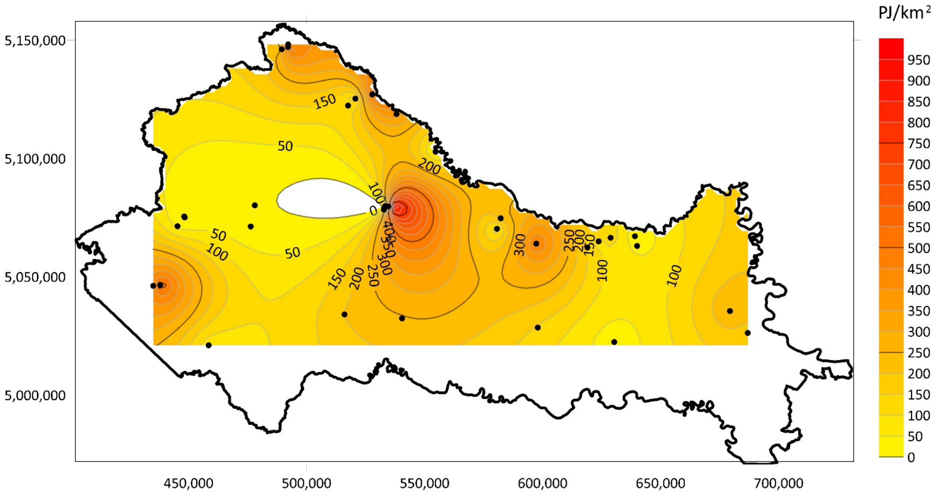


Figure 18. Mean heat-in-place areal distribution—pre-rift phase.

In order to determine the accuracy and applicability of the heat-in-place calculation according to the Gringarten method and the probability distribution, the obtained data for a single lithological unit were modelled in the software programme Tough2. For this purpose, typical wells were taken for each lithological unit, and a doublet model involved in the production of thermal energy was created. A typical modelling cube is taken as three times the modelled well spacing, and the thickness is presumed as the thickness of each lithological unit determined in the well. A polygonal mesh with a cell size of 10,000 m^3 was used, while a refinement of 5 m^3 was applied around the wells. Input parameters for each model, i.e., well doublet, are presented in Table 4. All three models were prepared for different lithological units within Drava Depression. The results of the simulation of the temperature movement between a pair of wells are shown in Figure 19. The modelling confirmed the penetration of a cold waterfront on the production well over a period of 30 years, with a temperature variation of 3.29% for the pre-rift phase, 6.03% for the syn-rift phase, and 4.75% for the post-rift phase (Figures 20–22). In addition, the model showed temperature stability over the 20-year period; in year 20, the temperature at the production well decreased by 0.44% for the pre-rift phase, 1.57% for the syn-rift phase, and 1.31% for the post-rift phase.

Table 4. Input parameters for model.

	Initial Pressure (bar)	Initial Temperature (°C)	Reservoir Depth (m)	Reservoir Thickness (m)	Reservoir Porosity (%)	Reservoir Permeability (m^2)	Doublet Spacing (m)	Production Rate (L/s)
Post-rift	374.00	132.00	2668.00	1053.00	13.30	9.40×10^{-14}	307.80	66.24
Syn-rift	341.00	152.00	3388.00	719.00	7.90	2.81×10^{-13}	704.65	331.77
Pre-rift	233.00	149.00	3721.00	217.00	12.90	6.20×10^{-14}	873.00	115.00

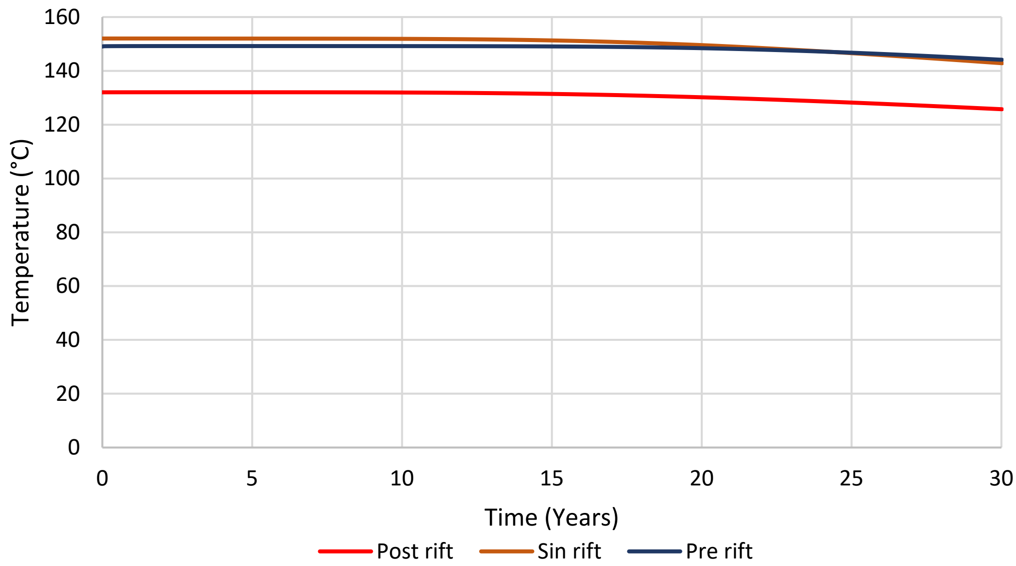


Figure 19. Temperature change around a doublet in the simulation programme.

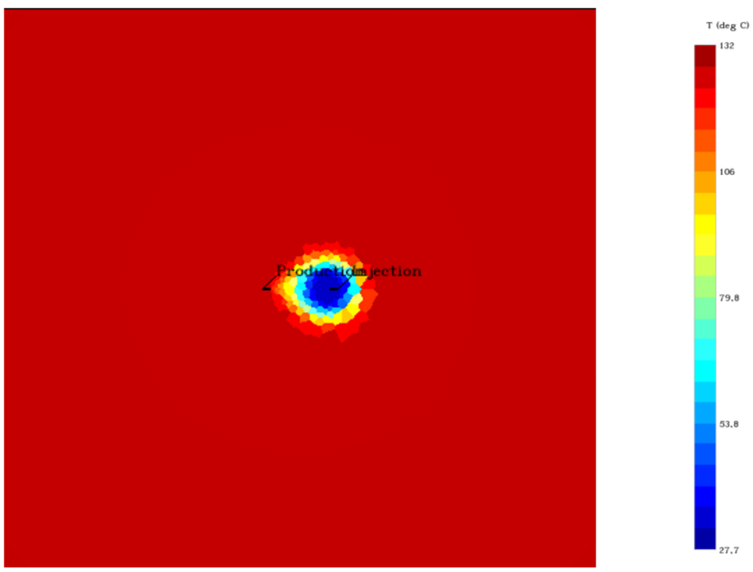


Figure 20. Model simulation of well doublet temperature distribution after 30 years of production—post-rift phase.

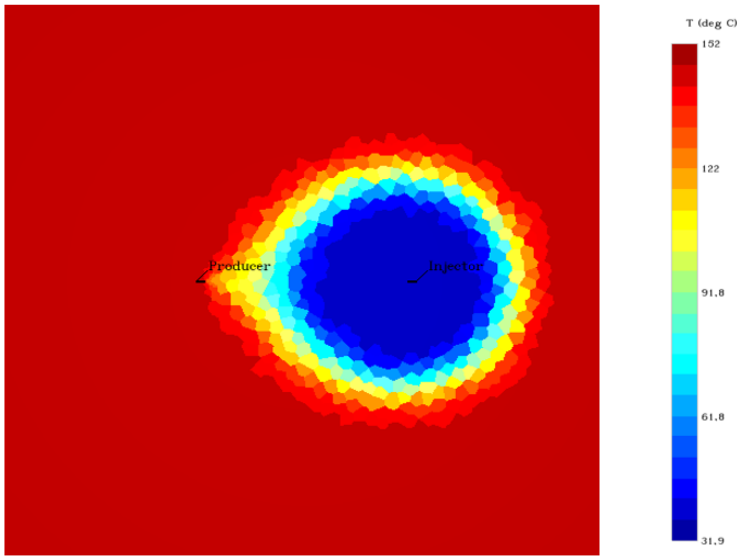


Figure 21. Model simulation of well doublet temperature distribution after 30 years of production—syn-rift phase.

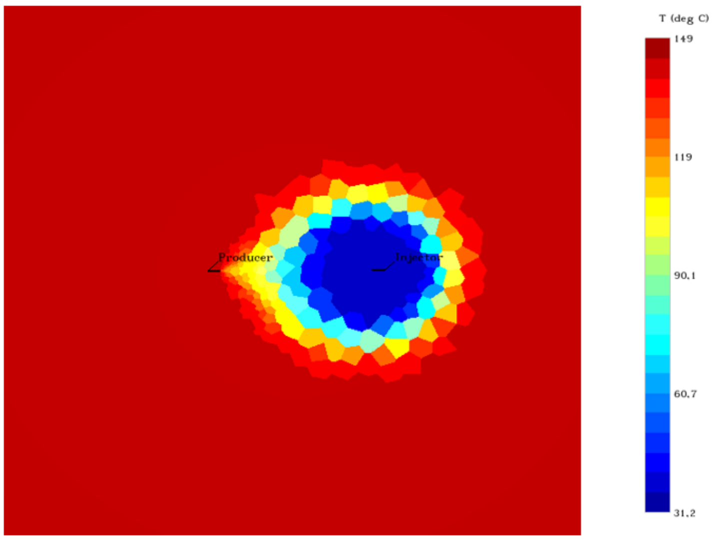


Figure 22. Model simulation of well doublet temperature distribution after 30 years of production—pre-rift phase.

4. Conclusions

To date, as part of a broader screening process conducted by the lead author and the Croatian Hydrocarbon Agency, drilling data, geophysical exploration data, and well testing data from more than 181 well sites have been initially collected and categorised or are in the process of research. This study on the analysis and modelling of the heat-in-place assessment with probability distributions is the first of such work for the Republic of Croatia. Previously, individual spatial assessments were made based on temperatures measured at the bottom of the wells. Together with the realisation of CPBS potential based on heat flow, the need emerged to identify more detailed areal data that would guide the development of geothermal potential and increase its share in the overall energy balance. By creating a model that shows how we can look at the total amount from a maximum of 2094.25 PJ to a mean of 537.33 PJ to a minimum of 14.43 PJ heat in place and involves only analysed well doublets in each lithological unit, the first step was taken to further identify individual areas for different uses of geothermal water—with uses from heating to electricity generation.

The use of the Gringarten model provides an opportunity for a preliminary assessment of the area and gave us the opportunity to model the reservoir in terms of the layout and number of wells that can function on the delineated geothermal reservoir. By comparing the values obtained by heat-in-place modelling using the estimated distance between the well doublets with the data obtained by the numerical simulation, we can see that the data obtained are consistent with the values obtained by the numerical simulation. The temperature difference at the production wells at the time of cold waterfront intrusion over a 30-year period is 3.29% for the pre-rift phase, 6.03% for the syn-rift phase, and 4.75% for the post-rift phase. Since data from wells were used to create the model, it can be concluded that the obtained values of heat in place support and confirm the obtained estimates. At the same time, due to the fact that point data were used and the estimation was made for a well doublet, we can speak of conservative estimates, as they do not take into account the volume of the entire geothermal reservoir but only the volume included in well doublet production. Considering the presentation of the method, we can conclude that the geothermal potential in the Republic of Croatia is larger than estimated, and further studies should focus on the estimation of geothermal potential included in the full area of each lithological unit. Since the heat-in-place value provides information about the potential of the reservoir, the next steps that would follow relate to the further categorisation of the reserves; according to Rybach [12], after the theoretical assessment, it is necessary to determine the technical and economic potential. For such an assessment, the analysed data should be categorised in terms of temperature constraints for the possibility of utilisation in terms of the measured temperatures, in order to then determine an extraction factor for them that would also reveal the economic potential.

The aquifer potentials associated with oil and gas fields were not part of this assessment. Alongside sites that initially only contained geothermal brine, there is a long history of hydrocarbon exploration and exploitation in the Croatian part of the Pannonian Basin. Therefore, there are high numbers of bottom-type aquifers available for further research on matured oil and gas fields. Bottom-type aquifers usually have good potential to be used as a geothermal energy resource once hydrocarbon production is terminated.

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