The model of heat potential from geothermal reservoirs and aquifers of oil and gas fields on the territory of the Republic of Croatia

Tuschl, Martina

University of Zagreb

Faculty of Mining, Geology and Petroleum Engineering

Martina Tuschl

THE MODEL OF HEAT POTENTIAL FROM GEOTHERMAL RESERVOIRS AND AQUIFERS OF OIL AND GAS FIELDS ON THE TERRITORY OF THE REPUBLIC OF CROATIA

DOCTORAL DISSERTATION

Zagreb, 2024

University of Zagreb

Faculty of Mining, Geology and Petroleum Engineering

Martina Tuschl

THE MODEL OF HEAT POTENTIAL FROM GEOTHERMAL RESERVOIRS AND AQUIFERS OF OIL AND GAS FIELDS ON THE TERRITORY OF THE REPUBLIC OF CROATIA

DOCTORAL DISSERTATION

Supervisor:

Professor Tomislav Kurevija, PhD

Zagreb, 2024

Sveučilište u Zagrebu

Rudarsko-geološko-naftni fakultet

Martina Tuschl

MODEL PRIDOBIVE TOPLINSKE ENERGIJE IZ GEOTERMALNIH LEŽIŠTA I VODONOSNIKA NAFTNO-PLINSKIH POLJA NA PODRUČJU REPUBLIKE HRVATSKE

DOKTORSKI RAD

Mentor:

dr. sc. Tomislav Kurevija, redovni profesor

Zagreb, 2024

Information about the mentor:

Professor Tomislav Kurevija, PhD

University of Zagreb

Faculty of Mining, Geology and Petroleum Engineering

Department of Petroleum and Gas Engineering and Energy

Acknowledgments

I would like to thank my mentor Prof. Tomislav Kurevija, Ph.D., who selflessly supported me during my doctoral studies, expanded my knowledge through discussions, encouraged me in my research, and unconditionally supported me at every step of the dissertation preparation.

Many thanks to the members of the committee, Marija Macenić, Ph.D., Prof. Daria Karasalihović Sedlar, Ph.D. and Prof. Stjepan Strelec, Ph.D. for the useful comments and the effort and time they invested in the dissertation. I would also like to thank all the anonymous reviewers of my research, whose comments helped to improve the quality of the dissertation.

I would like to thank my dear colleagues who were always there for me when I needed support, professional help, and advice. My special thanks go to Tatjana Durn, who always listened to me, supported me, made comments, and encouraged me when I needed it the most. I would also like to thank the Croatian Hydrocarbon Agency for their support and permission to use the data used for the analysis.

And finally, I would like to thank my mum and my sister - for everything!

ABSTRACT

The beginning of the use of geothermal energy in the Republic of Croatia started in the 1980s and was mainly related to the exploration of oil and gas, while the initial use was mainly related to the need for thermal energy, until recently the first geothermal power plant was put into operation.

A special feature of geothermal energy is its independence, i.e. its availability around the clock, which ensures the stability and security of the system, whether for the generation of electricity or heat. The geothermal potential is linked to the geological characteristics of the reservoirs, which makes it an energy source with a local character. It is important to assess the potential of an individual area so that the geothermal potential can be fully exploited. The assessment of geothermal potential is an important element in determining the possible temperatures of geothermal water, considering the wide spectrum of geothermal energy use and economic extraction.

The aim of this study is to determine the geothermal potential of the Croatian part of the Pannonian Basin. Data from 181 wells were analysed for the presence of inflow, temperature and porosity as well as permeability and volume for each well or lithological unit. Monte Carlo models were used to create a probability distribution of potential inflows from the well, while the dependence between productivity and permeability indices was determined for each individual lithological unit observed. As a result, geothermal potential was mapped according to the obtained values of heat in place for Croatian part of Pannonian Basin covered with analysed wells.

The Croatian oil fields are mostly at the end of their production, and during the production period the method of waterflooding was used as a secondary method to increase recovery. The deep aquifers of the oil and gas fields have the potential for geothermal energy production, and the possibility of using existing wells that could be used for geothermal energy production has been analysed.

In order to be able to use the existing infrastructure, especially the wells, the model of selecting a single well for the extraction of geothermal energy was analysed, focusing on the well completion. Indeed, the well completions as well as the depth of the well are a limiting factor in the selection of a well for future geothermal energy production. For this reason, it is necessary to determine the techno-economic possibility of converting each oil well into future geothermal energy through a preliminary analysis.

Keywords: geothermal energy, geothermal reservoir, heat in place, mature oil field, oil bottom aquifer.

PROŠIRENI SAŽETAK

Početak upotrebe geotermalne energije u Republici Hrvatskoj počine 80-tih godina prošlog stoljeća i uglavnom je vezana uz istraživanja provedena u svrhu eksploatacije nafte i plina, dok se početna upotreba veže uglavnom uz potrebe za toplinskom energijom, sve do nedavno, kada je s radom počela prva geotermalna elektrana.

Geotermalna energija kao obnovljivi izvor energije sve više dobiva na značaju u energetskim politikama država koje posjeduju geotermalni potencijal. Posebna značajka geotermalne energije je njezina neovisnost, odnosno dostupnost 24 sata u toku dana što osigurava stabilnost i sigurnost sustava, bilo za proizvodnju električne energije ili toplinske energije. Geotermalni potencijal vezan je na geološke karakteristike ležišta što ga čini energentom lokalnog karaktera te je važno procijeniti potencijal pojedinog prostora kako bi se geotermalni potencijal mogao u potpunosti iskoristiti. Procjena geotermalnog potencijala važan je element u određivanju mogućih temperatura geotermalne vode, a s obzirom na širok spektar upotrebe geotermalne energije te ekonomičnog pridobivanja.

Hrvatski geotermalni potencijal usko je vezan uz Panonski bazen i njegove geološke karakteristike na prostoru Republike Hrvatske. Dosadašnja istraživanja uključivala su pojedinačne lokacije bez opsežne analize cjelokupnog prostora te se pokazala potreba za analizom dostupnih bušotinskih podataka, a koji su potvrdili postojanje dubokih vodonosnika, na način da se kvantificira i prostorno locira geotermalni potencijal.

Cilj ovog istraživanja je utvrditi toplinski potencijal hrvatskog dijela Panonskog bazenskog sustava, kako bi se procijenio toplinski potencijal geotermalnih ležišta. Analizirani su podaci s 181 bušotine koji se odnose na prisutnost dotoka, temperaturu i poroznost, kao i propusnost i volumen za svaku bušotinu, odnosno karakterističan litološki marker, uključen u procjenu. U geotermalnim ležištima jedan od najvažnijih podataka uz petrofizičke i termodinamičke podatke je potencijal bušotine, odnosno maksimalni protok pri određenim uvjetima propusnosti i poroznosti. Monte Carlo modeliranjem, napravljena je distribucija vjerojatnosti mogućih dotoka iz bušotine uz postavljanje ovisnosti između indeksa produktivnosti i propusnosti za svaku pojedinu litološku jedinicu koja je promatrana. Kao rezultat modeliranja, ekstrapolirani su dobiveni lokalni podaci toplinskog potencijala oko analiziranih bušotina te je na taj način mapiran geotermalni toplinski potencijal arealno distribuiran na prostoru hrvatskog dijela Panonskog bazena.

Republika Hrvatska ima dugogodišnju povijest istraživanja i eksploatacije ugljikovodika koja u Hrvatskoj traje već preko 70 godina. Hrvatska naftna polja uglavnom su u svojoj silaznoj putanji proizvodnje, a tijekom proizvodnog vijeka koristila se metoda zavodnjavanja kao sekundarna metoda povećanja iscrpka. Duboki vodonosnici naftnih i plinskih polja imaju potencijal za proizvodnju geotermalne energije te je analizirana mogućnost korištenja postojećih bušotina, a koje bi mogle naći svoju primjenu u proizvodnji geotermalne energije. Na taj način napravila bi se tranzicija naftne industrije prema obnovljivim izvorima energije, te ujedno smanjili troškovi korištenja geotermalne energije budući da bi se koristile postojeće bušotine.

Kako bi se mogla iskoristiti postojeća infrastruktura, posebice bušotine, analiziran je model odabira pojedine bušotine za proizvodnju geotermalne energije s fokusom na postojeću bušotinsku opremu. Naime, oprema ugrađena u bušotinu, kao i dubina bušotine stvaraju ograničavajući faktor prilikom odabira bušotine za buduću proizvodnju geotermalne energije te je iz tog razloga potrebno prethodnom analizom utvrditi tehno-ekonomsku mogućnost prenamjene svake pojedine naftne bušotine u buduću geotermalnu.

Ključne riječi: geotermalna energija, geotermalna ležišta, toplinski potencijal, zrelo naftno polje, vodonosnici naftnih polja.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 INTRODUCTION

In 2021, the total capacity of electricity generation in the Republic of Croatia was 4.872,9 MW. Of this, hydroelectric power plant capacity accounts for 2.200,5 MW, while renewable sources such as wind, solar, geothermal and biomass account for 1.289,5 MW of production capacity. In this total of renewable sources, geothermal energy accounts for a share of 0,78% (Ministry of Economy and Sustainable Development, 2021). Considering the average geothermal gradient for the Pannonian Basin of 0.049 °C/m^2 and a heat flow of 76 mW/m^2 , it is considered that the Republic of Croatia has significant geothermal potential that is underutilised for the production of this renewable energy source (Jelić, 1979; Jelić, et al., 1995).

The use of geothermal energy in Croatia, which started in the late 1980s, developed very slowly and sporadically. Most projects and uses are related to balneology and the use of geothermal water in spas and to a lesser extent for heating purposes (Borović & Marković, 2015; Marković, et al., 2015). In the last decade, the use of low-temperature geothermal sources in agriculture has increased, especially for heating greenhouses. In 2022, there are seven geothermal fields in Croatia, one of which produces electricity (Velika Ciglena), while others are using geothermal energy for heating purposes – greenhouses and some of them for hotel complexes.

1.1. Overview of study area

The development of geothermal potential is closely related to the exploration and exploitation of oil and gas. The sporadic exploitation of geothermal energy began in Croatia in fields discovered during oil and gas exploration that did not yield the expected results.

Recently, interest in the use of geothermal energy has increased, leading to an increasing number of exploration permits. This is mainly related to the increased demand for the use of geothermal energy for heating purposes. For this reason, the number of permits for exploration of geothermal potential has increased sharply, so that in 2022 there were a total of 14 permits for exploration. Of these, 8 permits relate to exploration for the purpose of electricity generation, while the rest are for heating purposes (Ministry of Energy and Suinstable Development, 2023). The Drava Depression is the most prolific region of the Croatian part of the Pannonian Basin for geothermal energy development. The geothermal gradient in the Drava Depression varies between 4.5 and 6.5 °C/100m (Macenić, et al., 2020). Due to the good geothermal properties of the Drava Depression, most of the licences are located within the Drava Depression and there is a possibility that the geothermal potential will greatly increase due to deep gas fields within the Drava Depression after the hydrocarbon lifetime expires (Kurevija & Vulin, 2011).

Since the geological data available and the research carried out so far indicate a high geothermal gradient in the area of the Croatian part of the Pannonian Basin, there is no clear and verifiable assessment of the thermal potential that can be obtained from geothermal energy on the territory of the Republic of Croatia. In the absence of a comprehensive analysis of the thermal potential of geothermal energy, there is a need to quantify and localise the areas with geothermal potential in the Croatian part of the Pannonian Basin through scientific research, based on the available geological, geophysical, petrophysical and thermodynamic data obtained from a large number of wells that confirmed the existence of aquifers in reservoirs.

In order to make a theoretical assessment of the heat potential from geothermal energy (Heat in Place - HIP) of the Croatian part of the Pannonian Basin, data from wells drilled for the purpose of hydrocarbon exploration but turned out to be negative, i.e. there was an inflow of water in the target reservoir were analysed. The data from wells drilled for hydrocarbon exploration have become a valuable source of information, considering that measurements, especially drill stem tests, were carried out at many wells, providing data on the reservoir permeability, flow, temperature, and coverage of the well's drainage radius. In this way, the presence of water in all wells was proven through tests during the construction of the well, and the presence of water saturation was proven, reducing the risks of the assessment itself.

In order to reduce geological risks and at the same time reduce initial investment, it is necessary to consider developing geothermal potential from hydrocarbon fields that are proven to have high temperature bottomdrive aquifers. After the end of hydrocarbon exploitation, under certain conditions, it is possible to convert oil fields into geothermal fields, taking into account the possibility of using the existing subsurface and surface infrastructure. In the Republic of Croatia, most oil and gas fields currently being exploited are in a state of high depletion. In most of the fields, secondary methods of hydrocarbon extraction are used, i.e. the process of waterflooding, which means that most of the oil fields also have a natural water pressure regime, which presupposes the potential for the use of geothermal energy if the reservoir pressure when leaving the reservoir is relatively close to the initial static pressure.

Geologically, the subject of this study was the Croatian part of the Pannonian Basin. Croatia is divided into two different units in terms of geothermal potential. The Mohorovičić discontinuity in the Pannonian Basin varies between 30 and 20 km, resulting in an average geothermal gradient of 0.049 °C/m and a heat flux of 76.0 mW/m^2, thus showing an above average geothermal potential in Europe (Jelić, et al., 1995). The Mohorovićič discontinuity increases to 40 km in the Dinarides (Šumanovac, et al., 2009). It is an area with an average geothermal gradient of 0.018 °C/m and a heat flux of 29.0 mW/m^2, which means that it does not have significant geothermal potential (Horváth, et al., 2015).

The Pannonian Basin (PB) is an area of predominantly lowland bordered by the Carpathians, the Dinarides and the Alps (Royden, et al., 1983; Royden, 1988). The Croatian part of the Pannonian Basin System (CPBS) is located on the southwestern edge of the Pannonian Basin and is divided into four main depressions called the Sava, Drava, Mura and Slavonian Sriem (Velić, et al., 2012).

In general, there were three main tectonic phases during the development of the CPBS (Horvath & Royden, 1981; Horvath, 1993; Lučić, et al., 2001; Pavelić, 2001; Tari, 1993; Tari & Pamić, 1998). The first phase (Pre-rift phase) is represented by igneous, metamorphic, and sedimentary rocks from the Palaeozoic and Mesozoic. The boundary between the phases is visible in the well logs as the regional marker Pt (Figure 1). Regional markers are identical features that can be identified on electrologues, or more precisely on resistivity curves. According to Saftić and Malvić (Saftić & Malvić, 2008), markers are characterised by clear and easily recognisable features in a given area. They are defined by similar resistivity values that are repeated in wells drilled in the regional area (Velić, 2007). The second phase (sin-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 sin-rift phase is very heterogeneous and consists of volcanic and pyroclastic rocks, breccias and conglomerates, sandstones, limestones, calcareous marls, etc. (Saftić, et al., 2003). During the Sarmatian (Horvath & Tari, 1999), minor compression (early post-rift) occurred, resulting in widespread pre-Pannonian unconformity, visible on well logs as regional marker Rs7 (Figure 1). 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 (Ćorić, et al., 2009; Royden, 1988; Velić, et al., 2012; Vrbanac, et al., 2010). 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 1). 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 (Ćorić, et al., 2009; Velić, et al., 2002; Malvić & Velić, 2011).

Figure 1 shows schematically the geological column of the Pannonian Basin and the distribution of the megacycles. The aim of the research conducted in this dissertation was to analyse the geothermal potential using wells drilled mainly in the Sava and Drava Depression. The objectives were three megacycles - pre-rift, sin-rift and post-rift phases.

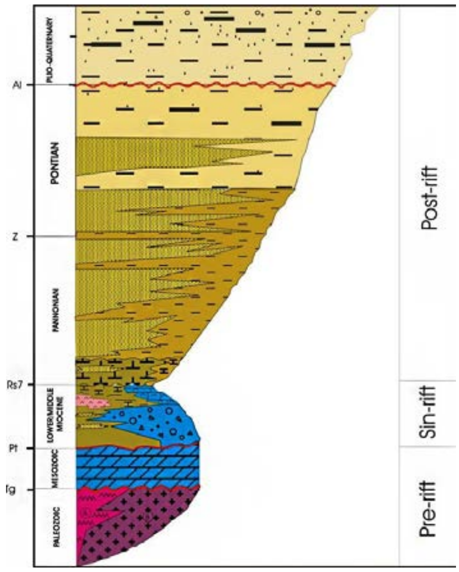


Figure 1. Schematic geological column of the Pannonian basin *(Durn & Krpan, 2016; Saftić, et al., 2003)*

1.2. Overview of research on heat potential of geothermal energy

Five categories have been proposed to classify geothermal resources, according to which the potential can be classified, and they refer to theoretical, technical, economic, sustainable and development potential (Rybach, 2015). The assessment of thermal energy contained in the reservoir (Heat in Place - HIP) is used as a standard method for assessing geothermal potential in the exploration phase when not all reservoir data is available. The method was proposed by Muffler and Cataldi (Muffler & Cataldi, 1978; Muffler, 1979) and introduced by the United States Geological Survey (USGS).

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:

$$H = (C_{vi}) \times (V_i) \times (T_i - T_0) \qquad (1)$$

$$H_i = H_r + H_w = (\Phi\, \rho_w\, c_w)\, (V_i)\, (T_i - T_0) + (1 - \Phi)(\rho_r\, c_r)\, (V_i)(T_i - T_0) \qquad (2)$$

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).

Exploring geothermal potential is a great risk, especially in areas where there is not enough data (McVeigh, et al., 2007; Miranda, et al., 2020). For this reason, due to their affordability, geophysical electrical methods are often used, which vary according to the objective sought (Kana, et al., 2015; Mignan, et al., 2019). For estimating geothermal potential, especially in data-poor exploration activities, heat in place is used as the standard method for estimating geothermal resources. This method was one of the first to be introduced by the United States Geological Survey and has been used for assessing geothermal potential ever since (Van Wees, et al., 2012; Kramers, et al., 2012; Koltzer, et al., 2023).

The assessment of heat recovery as part of the technical classification of geothermal potential affects the overall share of potential, and overestimation of geothermal potential and especially geothermal energy recovery can be misleading when planning future power plants and optimising geothermal field development (Franco & Vaccaro, 2020; González-García, et al., 2021), so the sensitivity of the parameters used must be taken into account (Kahrobaei, et al., 2019). The sensitivity and key parameters for estimating the geothermal potential of the method have been revised by several authors, resulting in the use of a combination of the Monte Carlo method and the USGS method for estimating the geothermal potential. The Monte Carlo simulation uses multiple trials to determine the value of a random variable. The probability distribution of the input variable provides an estimate of the total uncertainty in the prediction of the final calculation (Kalos & Whitlock, 2008). In some cases, however, this can lead to an overestimation of the potential, which is why a modification of the method is suggested when it comes to recoverable potential (Garg & Combs, 2015).

In this study, the assessment of heat in place was based on well data, it is necessary to determine the surface intervention on which the potential demonstrated by well testing is predicted. For this reason, the analysis assumed a pair of wells, of which the well where the potential was proven by testing results is the production well, while the spacing of the injection well was assumed based on the Gringarten method (Gringarten & Sauty, 1975; Gringarten, 1978) for determining the spacing between well-doublets. The method assumes continuous production of the brine for 30 years with no drop in temperature. By combining the assumed volume around the wells, the modelled flows through the well, which were modelled using the Monte Carlo method in such a way that the permeability and individual productivity index of each well were made dependent, heat-in-place assessment maps were created for the Croatian part of the Pannonian Basin and subdivided by regional markers, i.e. geological megacycles -Pre-rift, Sin-rift and Post- rift phase.

Since the exploration and production of geothermal energy is very capital intensive, it is necessary to make the best use of existing infrastructure to reduce these costs. The cost of drilling geothermal wells is 40% of the total investment (Sveinbjornsson & Thorhallsson, 2012) and can reach up to 50% of the total investment (Stefansson, 2002; Kipsang, 2015) for electricity generation from geothermal waters, so great attention should be paid to the drilling cost of geothermal wells. The drilling technology and cost of geothermal wells are closely related to the oil industry and the cost of drilling oil and gas wells, but the cost of drilling geothermal wells can be even higher than the cost of drilling an oil or gas well at the same depth (Augustine, et al., 2006). The main problem associated with geothermal drilling is the high temperature of the reservoir and the associated higher cost of equipment, as materials resistant to high temperatures must be used (Teodoriu & Falcone, 2009). The final price of a geothermal well is influenced by many factors, such as the final depth of the well, the lithology of the site where the well is drilled, the drilling rig used for the well, the final design of the well's equipment and, finally, unplanned situations that lead to an increase in the construction time of the well, and thereby increase the price of the well. Even with high initial costs, geothermal energy competes with other renewable energy sources because the emphasis on geothermal energy as a stable, baseload renewable energy source that can compete with wind and solar energy through greater efficiency than other renewable energy sources is often overlooked (Dumas & Angelino, 2015).

In order to maximise the use of geothermal energy and reduce its cost, many authors have addressed the issue of using oil fields for geothermal energy needs, examining the methodology of selecting favourable oil fields and the methods of extracting geothermal brine from reservoirs (Hranić, et al., 2021; Kurnia, et al., 2022; Westphal & Weijermars, 2018; Li & Sun, 2015; Nian & Cheng, 2018; Wang, et al., 2018; Wang, et al., 2018; Wang, et al., 2016; Caulk & Tomac, 2017; Macenić & Kurevija, 2018). At the same time, much attention has been paid to the use of deep heat exchangers in abandoned oil wells and the direct use of geothermal energy, as well as to equipping oil wells with two-pipe heat exchangers and using a secondary fluid as the working fluid. In this way, the net energy generated at a well temperature of 450 K can be more than 3 MW (Bu, et al., 2012; Davis & Michaelides, 2009; Gharibi, et al., 2018).

In addition to the possibilities of using geothermal energy through new exploration activities and the exploitation of greenfield sites, it is particularly important to consider the possibilities of using deep aquifers of oil fields for the production of geothermal energy, given the infrastructure of the oil industry in Croatia. As oil and gas production has been going on continuously for almost 70 years, many fields are nearing the end of production. Moreover, almost all oil fields in Croatia have been waterflooded, which argues for an easier continuation of geothermal brine production, as reservoir pressures are close to the initial reservoir pressures. It is possible to convert oil fields to geothermal while oil production is still ongoing by using wells that have penetrated deep aquifers and are no longer used for oil production. This possibility was analysed in this dissertation using the example of an oil field that is still in production. The existing well completion is a limitation of such geothermal production, as it is also an obstacle to realising the large flows necessary for energy production.

1.3. Objectives and hypotheses of research

The main objectives of the research focus on:

1) Definition of the geological, petrophysical, thermodynamic and technical parameters required for modelling the heat potential of geothermal energy from geothermal reservoirs.
2) The creation of a model for estimating the thermal potential of geothermal energy in the Croatian part of the Pannonian Basin and an analysis of the currently used geothermal potential.
3) The quantification of the possibility of using the estimated thermal energy in the energy process (thermal energy/electrical energy).
4) The creation of a model for the conversion of hydrocarbon fields into the use of geothermal water from deep aquifers.

To achieve the research objectives, two hypotheses were tested: (1) the geothermal gradient of the Croatian part of the Pannonian Basin offers better opportunities for the use of geothermal energy for energy conversion; and (2) hydrocarbon production fields can be converted into geothermal production fields, reducing the economic constraints on the use of geothermal water for energy purposes.

1.4. Structure of the dissertation

The dissertation is a synthesis of research, analysis and models described in three scientific papers, each focusing on the objectives and hypothesis of the dissertation. The introductory part presents the approach of the dissertation and the objectives and hypotheses that are discussed. After the introductory part, each individual part of the research is presented as a scientific paper in Chapter 2. First original scientific paper provides an overview of previous activities related to geothermal energy exploration and use, as well as current exploration permits and plans to move forward with the exploration of geothermal potential in these areas. The development areas, their status and potential are also presented. The assessment of the geothermal potential is presented in second original scientific paper in the way that the data from the wells was analysed and a model was created, on the basis of which the heat potential of the Croatian part of the Pannonian Basin was determined. Possibility of extracting geothermal brine from the aquifer of a deep oil field based on an applicable model of an oil field in production and possibilities of selecting suitable wells for brine extraction, as well as the energy potential of the selected wells and numerical modelling of the entire field is presented through third original scientific paper. Chapter 3 discusses the results of the individual papers in relation to the hypotheses put forward and provides an overview of future research. In the last Chapter 4, the conclusion of the entire research is given.

2. ORIGINAL SCIENTIFIC PAPERS

Tuschl, M., Kurevija, T., Krpan, M., Macenić, M. (2022) Overview of the current activities related to deep geothermal energy utilisation in the Republic of Croatia. Clean Technologies and Environmental Policy, 24 (10), 3003–3031, https://doi.org/10.1007/s10098-022-02383-1.

Clean Technologies and Environmental Policy
https://doi.org/10.1007/s10098-022-02383-1

ORIGINAL PAPER

Overview of the current activities related to deep geothermal energy utilisation in the Republic of Croatia

Martina Tuschl[1] · Tomislav Kurevija[2] · Marijan Krpan[1] · Marija Macenić[2]

Received: 8 January 2022 / Accepted: 9 August 2022

Abstract
The Pannonian Basin, partly located in Croatia, is well known for its higher-than-average geothermal gradient with good potential for geothermal energy exploitation. Most of the currently known geothermal potential locations in the Croatian part of the Pannonian Basin (CPB) were discovered during the oil and gas exploration and exploitation from the mid-twentieth century onward. Unfortunately, recent geothermal energy utilisation in Croatia, which began in the late 1980s, developed very slowly and sporadically, even though the utilisation of it has been known since the Roman times. Most of the discovered geothermal sources are used for balneology in numerous thermal spas. In the last decade, low-temperature geothermal resources have also been used in agriculture, namely in greenhouses. However, with the change of legal framework in 2018, the market showed an increase in the number of issued geothermal exploration blocks. With Croatia's first geothermal ORC power plant Velika 1, commissioned in 2019, the interest in developing geothermal projects is seen in 13 exploration and six production licenses issued in the last three years, focusing on deep geothermal potential. The planned use of these granted licenses varies from electricity production to agricultural use. Aside from classic geothermal brine production, there is also a good potential of geothermal brine exploitation from bottom aquifers in depleted oil and gas fields. Many hydrocarbon reservoirs in Croatia consist of oil and gas in the upper part of the reservoir and aquifer in the bottom part. During initial depletion-drive exploitation, pressure in the reservoir declines, causing brine from the aquifer to slowly invade the oil zone. While the reservoir is in its final stages of production, some waterflooded peripheral wells could be turned into geothermal ones, even if oil is still produced or after the field is abandoned. So far, several locations with relatively high temperatures of the bottom aquifer have been identified as a good potential for deep geothermal energy exploration and exploitation. This work gives an overview of the current state of geothermal energy utilisation in Croatia and future prospects.

✉ Tomislav Kurevija
tkurevi@rgn.hr

Martina Tuschl
martina.tuschl@azu.hr

Marijan Krpan
marijan.krpan@azu.hr

Marija Macenić
marija.macenic@rgn.hr

[1] Croatian Hydrocarbon Agency, Zagreb, Croatia

[2] Faculty of Mining, Geology and Petroleum Engineering, University of Zagreb, Zagreb, Croatia

Published online: 28 August 2022

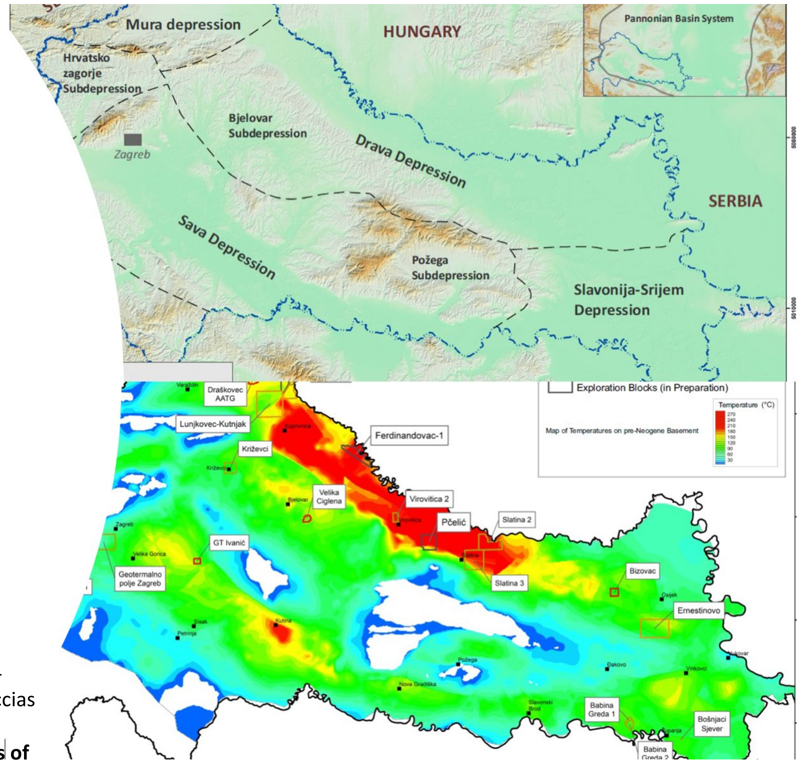
Graphical abstract

PANNONIAN AREA OF CROATIA AS GEOTHERMAL REGION

- Region with high potential for the production of geothermal water for energy purpose (electrical and heat energy) according to data **from deep exploration wells in the Croatian part of Pannonian basin**
- **Geothermal potential has been proven in cca 200 wells**
- **Above-average high geothermal gradient** (mean geothermal gradient of Pannonian area of Croatia) is **60 % higher than the European average**

LARGE CAPACITY GEOTHERMAL POTENTIALS:

- **Carbonate-clastic complex of Mesozoic age** (pre-Neogene basement): dolomites, limestones, breccias & conglomerates
- **Dolomite breccias and Lithotamnium limestones of Neogene**
  - Occurrence as massive reservoirs with significant productivity – (capacity of several thousand m^3/d)
  - Petrophysical characteristics: intergranular porosity, double porosity (fractured carbonates), good permeability



Map of Temperature of pre-Neogene Basement

Introduction

As part of a global effort to fight climate change, the promotion of geothermal energy utilisation has been recognised in all EU strategic documents related to the national Member States' plans to reduce greenhouse gases emissions. Energy transition shift from hydrocarbon exploration and exploitation projects towards geothermal brine production is also gaining momentum in the Republic of Croatia. Since the country has long history of domestic oil and gas production, more than 4,000 deep wells have been drilled, mainly in the Pannonian basin. Deep geothermal reservoirs can often be found in a form of bottom-type aquifers, which are an integral part of oil–water reservoir systems. Such aquifers play an important role as a strong energy drive to produce oil from permeable rock. On the other hand, during hydrocarbon exploration drilling, numerous geothermal reservoirs were discovered without the presence of hydrocarbons in different geological environment (Fig. 1). These locations are now frontrunners of geothermal energy research, as well as part of public concessions, a process which is handled by the Croatian Hydrocarbons Agency. The first activities began in the early twentieth century, and along with oil and gas, exploration of geothermal waters started. Testing of wells revealed the presence of a hot aquifer, but for a long time there was no further development of geothermal potential. The beginnings of the use of geothermal water for commercial purposes started in the late 1980s in the Bizovac field, and it is considered to be the longest use of geothermal water for space heating and balneological purposes in the contemporary times. Unfortunately, the application of geothermal water for energy utilisation in Croatia has developed slowly and sporadically while the development of geothermal water for balneological purposes is highly

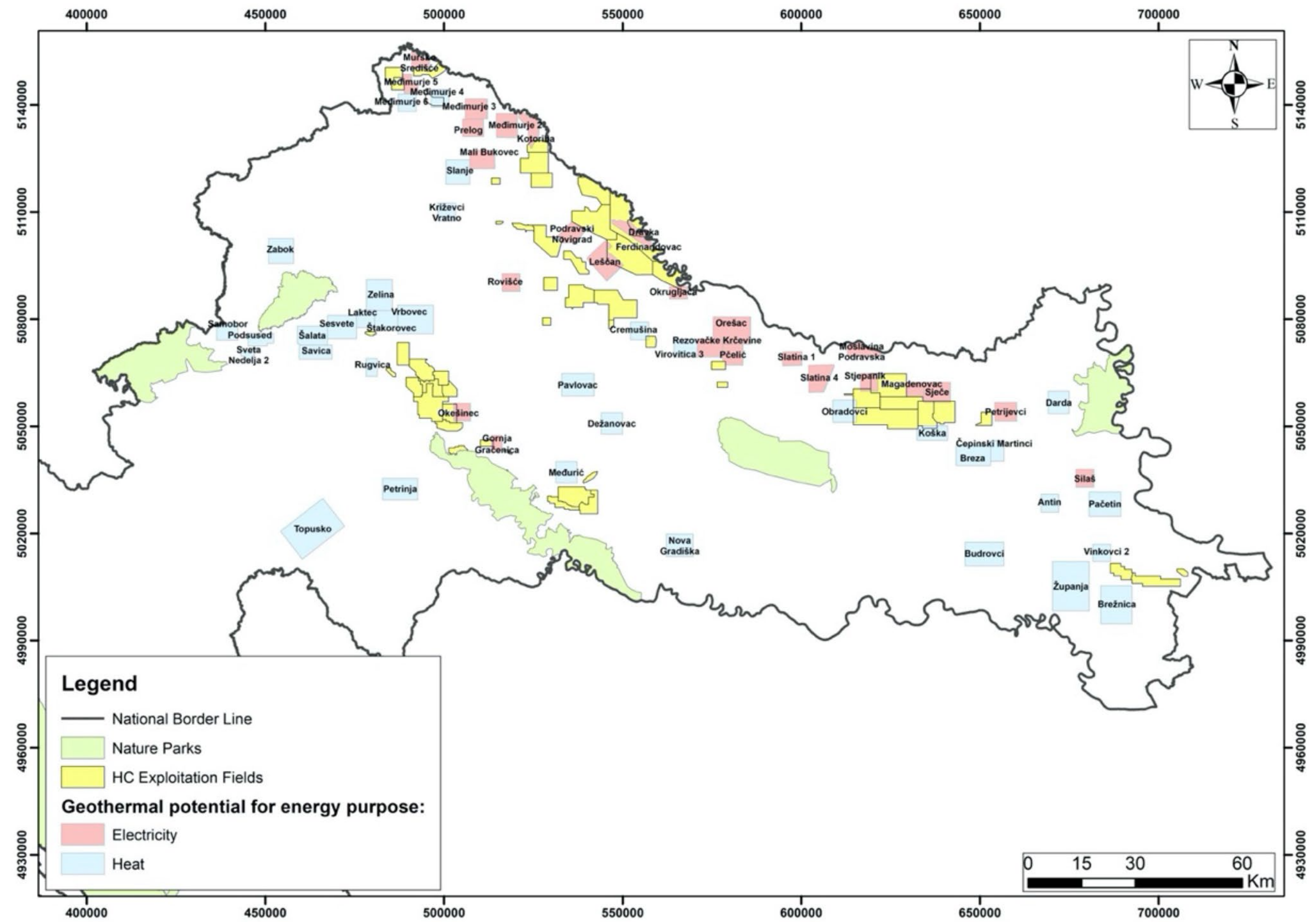


Fig. 1 Existing hydrocarbons exploitation fields and located geothermal potential reservoirs during hydrocarbons exploration era

developed through natural springs and tourist purposes (Lund and Toth 2020). Geothermal water for balneological purposes exists in Croatia at almost 21 sites with installed thermal energy of 24.0 MW_t (Živković et al. 2019), and most of the sites, 16, are located in Hrvatsko Zagorje (Borović and Marković 2015). The geochemical analysis of those sites showed that the associated geothermal reservoirs are in dolomite (Marković et al. 2015). A more intensive period of exploration of geothermal waters began in 2018 when the legislative framework in Croatia changed with the new Act on the Exploration and Production of Hydrocarbons (Official Gazette 52/18; Official Gazette 52/19; Official Gazette 30/21). The Croatian legal framework offers two options when tendering geothermal water for a given area. The tender can be launched by an investor's initiative for a specific area, or the Ministry responsible for energy initiates the tender in the areas where a certain geothermal potential has been assessed. The Croatian legal framework divides activities related to geothermal waters into exploration and exploitation phases. Exploration and exploitation permits are granted in a single procedure, i.e. if the investor fulfils his obligations from the exploration phase, he is automatically granted an exploitation permit. The exploration phase lasts a maximum of 5 years and can be extended for another year. The time frame for the exploration phase is a biddable item, so that the investor can bid for a shorter exploration phase. After commercial discovery, the investor proves its reserves through a reserve study and enters the exploitation phase based on the proven reserves. The exploitation phase lasts 25 years and can be extended if the investor proves that there are reserves that can be exploited commercially (Fig. 2).

Geological setting and geothermal potential

The Mohorovičić discontinuity in the Pannonian Basin varies from 30.0 km to 20.0 km, while its depth in the Dinarides is up to 40 km (Šumanovac et al. 2009), thus creating two very different geothermal regions in Croatia with different geothermal gradients. The Dinarides area

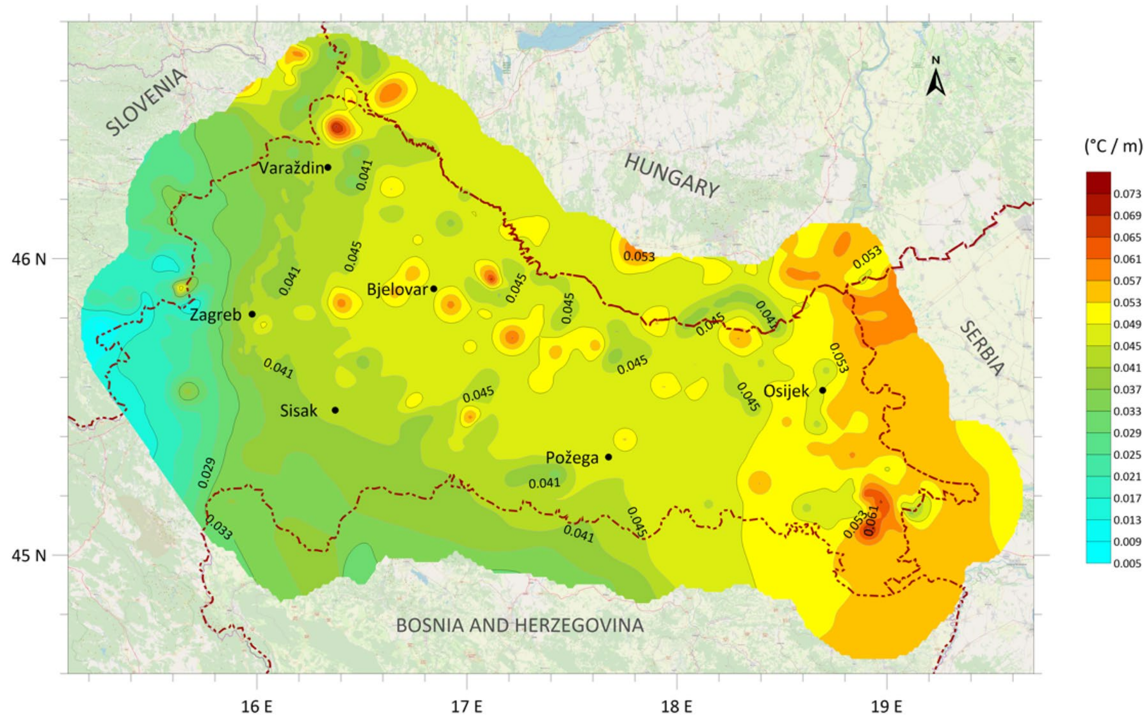


Fig. 2 Novel geothermal gradient map of the panonnian basin (Macenić et al. 2020)

has an average geothermal gradient of 0.018 °C/m with a heat flux of 29.0 mW/m^2 and thus has no significant geothermal potential, while the Pannonian Basin has an average geothermal gradient of 0.049 °C/m and a heat flux of 76.0mW/m^2 and thus has an above average geothermal potential in Europe (Jelić et al. 1995). The Pannonian Basin is characterised by low seismicity and high heat flux (Lenkey et al. 2002). A high heat flux, followed by high temperatures, has developed in the Pannonian Basin (Horváth et al. 2015). Recently, Macenić et al. (2020) presented a novel geothermal map of Croatia, based on gathered data from 154 deep exploration wells (Fig. 2).

Pannonian Basin (PB), as the largest Miocene–Quaternary basin, has been developed within the Alpine–Carpathian–Dinaridic orogenic system (Prelogović et al., 1998). According to Cvetković et al. (2019), the tectonic evolution of the PB started by the Cretaceous–Paleogene collision of Adria Microplate and European foreland. In the Early to Late Miocene, European plate roll-back subduction induced lithospheric extension and back-arc-type extension in the PB. The Neogene sedimentation process occurred within three 2nd-order megacycles, while majority of hydrocarbon source and reservoir rocks were formed during the 1st and 2nd megacycle (Saftić et al. 2003). The main source rocks are marly limestones and limy marls, while hydrocarbons are found in the Neogene basement, Miocence coarse grained clatics and Upper Miocene sandstone (Lučić et al. 2001). The extensional tectonics and the thinning of the crust and lithosphere within the Pannonian Basin are the cause of the high geothermal gradients and the very pronounced heat flux.

The Croatian part of the Pannonian Basin (CPB) is divided into four main depressions (Fig. 3): Mura, Sava, Drava and Slavonia Srijem (Velić et al. 2012). The Mura depression is located in the northernmost part of Croatia and extends from the border with Slovenia and Hungary in the north to a series of Žumberak, Medvednica and Kalnik mountains in the south. The Sava depression extends along the southwestern edge of the Pannonian Basin. The Drava depression covers most of the CPB and extends over the territory of the Drava River and is bounded by the state border with Hungary in the north and reaches the border with the Republic of Serbia in the east. The southern part of the Drava depression borders the mountains from Medvednica to Krndija. Slavonija–Srijem depression is located east of the town of Slavonski Brod and extends to the Serbian and Bosnian–Hercegovina borders and is the smallest of all depressions in the CPB (Malvić and Velić 2011).

The geothermal potential in the CPB is related to the pre-Neogene basement and Lower Neogene deposits (Fig. 4). The pre-Neogene basement is the most important correlation unconformity in the CPB and is visible in almost all well and

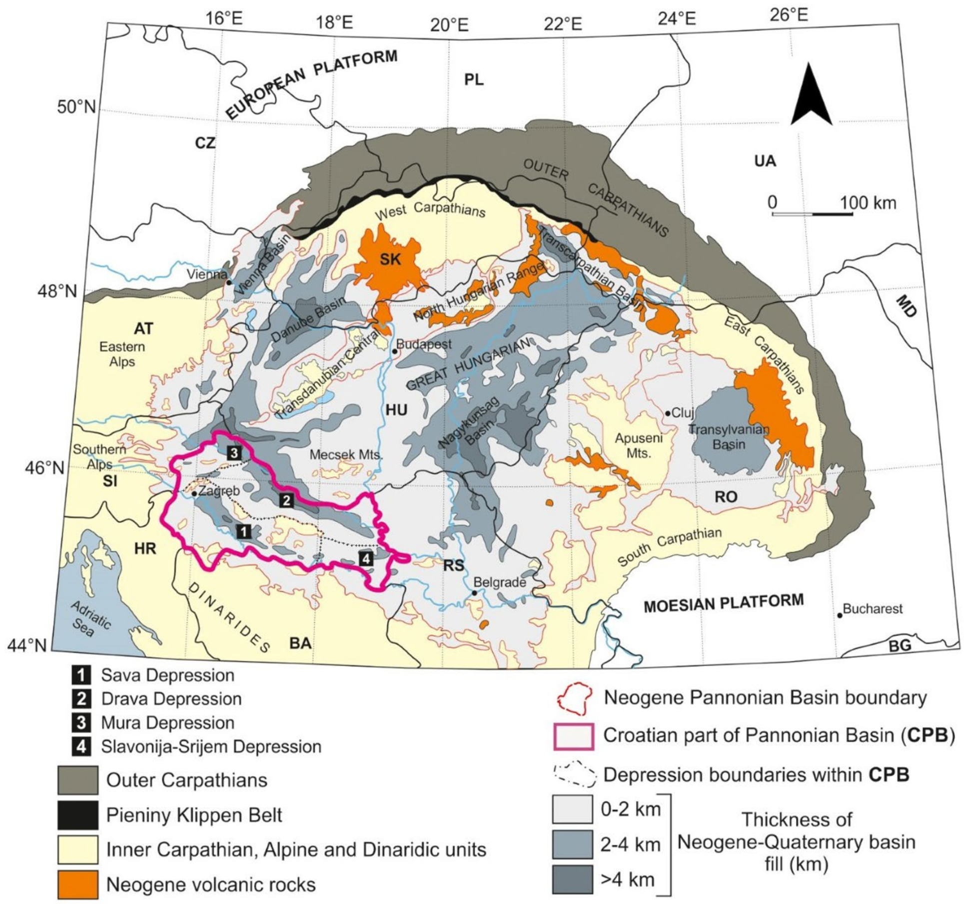


Fig. 3 Schematics of four main depressions in the Croatian part of the Pannonian Basin System (Velić et al. 2012)

seismic data (Saftić et al. 2003) and is characterised by high temperatures in almost the entire surface of the spreading (Cvetković et al. 2019). According to Royden et al. (1983), the evolution of the Pannonian Basin is subdivided into a syn-rift (Early to Mid-Miocene) and post-rift (Late Miocene to Quaternary) phase. The main geothermal plays in CPB are developed in pre-rift and syn-rift phase and considered as plays with high geothermal potential according to the present exploration activities in Croatia. There is a post-rift geothermal clastic play which is usually not a primary target of the geothermal exploration due to the lower geothermal gradient and flow.

Geothermal play developed in the pre-rift phase considers Paleozoic and Mesozoic age deposits and rocks (Sebe et al. 2020). According to the common lithostratigraphic classification, there are two lithological types of the pre-Neogene basement—predominantly Paleozoic magmatic and metamorphic rocks and Mesozoic carbonate deposits (Fig. 5). The Paleozoic, in locally accepted nomenclature "Crystalline Basement Rock", generally consists of granites, gabbro intrusions and fissured and altered metamorphised rocks intrusions. The petrophysical interpretation is based on well data which provide good characterisation of weathering zone, almost always located in the uppermost part of the rock, with secondary porosity. The weathering zone can extend from a few metres to several tens of metres from the top of the bedrock and mainly was formed during the Paleogene. (Malvić et al. 2020). The pre-Neogene deposits consist of carbonate deposits of Mesozoic age, mainly Triassic dolomites, while in the western part of the Pannonian Basin one can also find Jurassic limestones and dolomites as well as Upper Cretaceous Scaglia limestones. Pre-Neogene basement is the log marker "Pt (PN)" in most of the internal studies of CPB (Malvić and Cvetković 2013). The Mesozoic deposits are best preserved in greater thickness in the western part of the CPB. They consist of calcareous dolomite-breccia conglomerates, marly limestones or marbled limestones. It can be concluded that towards the eastern and southern parts of the CPB, they are entirely absent or isolated in the form of blocks or "lobes", which may affect the isolation of aquifers. Cracked massive carbonate deposits have been shown to be good aquifers. Geothermal play developed in syn-rift phase refers to the deposits from the Lower to Middle Miocene. They are defined by log markers from Pt (PN) to Rs7. They are mostly represented by large clastic

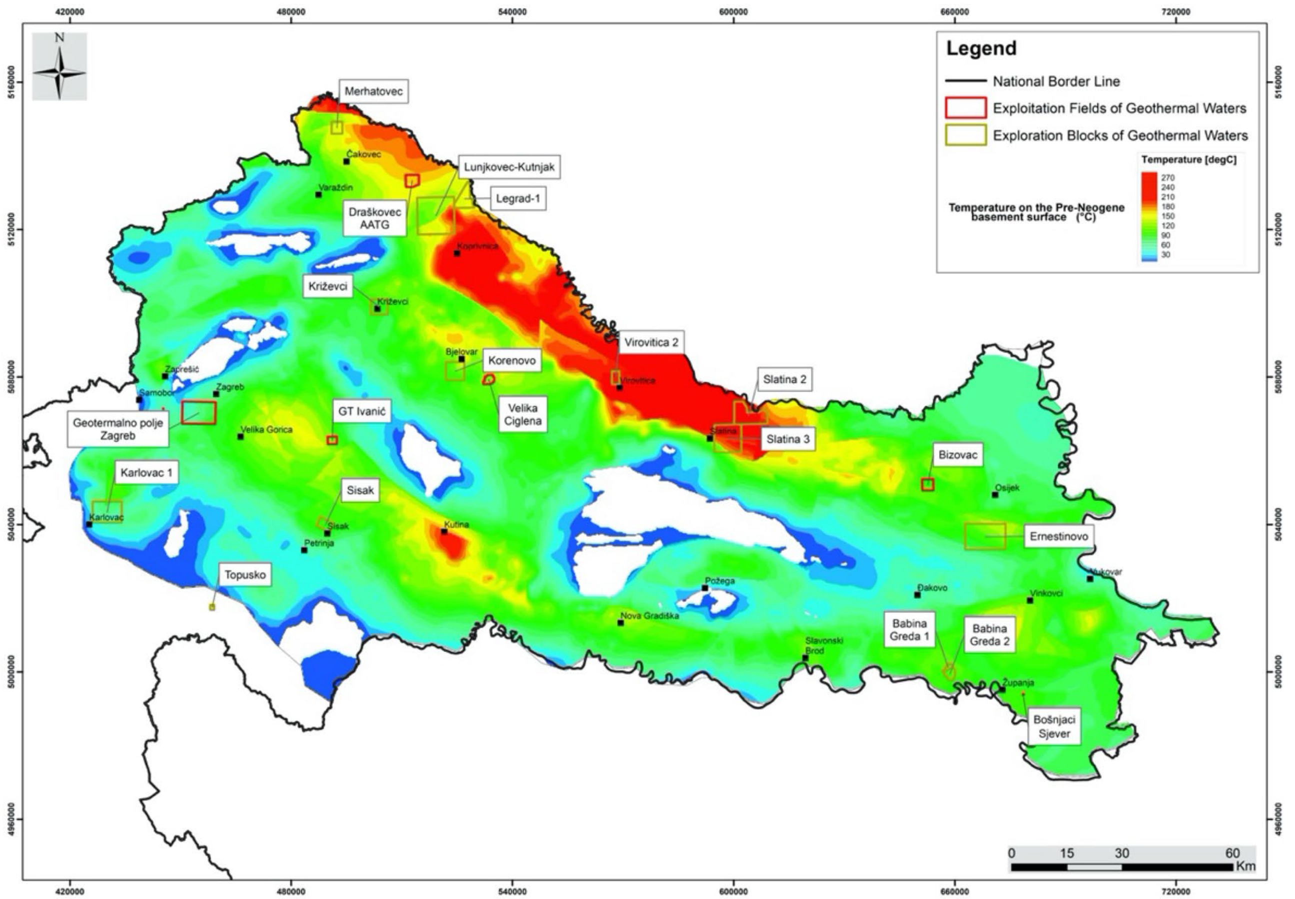


Fig. 4 Temperature of the pre-Neogene basement surface in the pannonian basin (Cvetković et al. 2019)

deposits in the lower parts of the formations, breccias and breccia conglomerates, which may be polymictic or carbonate. In the upper parts of the formations, there can be present sandstones of the lithoarenite or arkose arenite type, siltites, marly and sandy limestones of the biocalcarenite and biocalcrudite type (lithothamnium limestones) and marls (Malvić and Velić 2011).

Croatian geothermal exploration blocks

In 2018, new legal framework was adopted—Croatia's energy resources have been consolidated in one place, which is the basis for creating a positive investment climate in a country that rationally manages its resources. In this regard, special emphasis was placed on the great potential of geothermal and the exploitation of geothermal water for energy purposes. The procedure for assessing the hydrocarbon or geothermal potential and determining the tender conditions is carried out by the Croatian Hydrocarbon Agency, established by the Government of the Republic of Croatia. Currently, potential investors can use the newly formed Geothermal Virtual Data Room which covers geotechnical data of the Pannonian Basin. Access to reports of 191 potential geothermal wells, seismic data (Fig. 6) and GIS data are available for the screening process.

As of 2021, 13 exploration licenses and 6 production licenses for geothermal waters are active in Croatia based on the activities of the last three years (Fig. 7). All licenses are focused on the exploitation of deep geothermal energy. Shallow geothermal energy represents a potential (Macenić et al. 2018) that is underutilised in the zero-emissions energy transition. The Drava depression is the most prolific region of the CPB for geothermal energy development. The geothermal gradient in the Drava depression varies from 0.045 to 0.065 °C/m (Macenić et al. 2020). Due to the good geothermal properties of the Drava depression, most licenses are located within the Drava depression and with possibilities of high increase in geothermal potential from deep gas fields within Drava depression after hydrocarbon lifetime expiration (Kurevija and Vulin 2011). The planned use varies from electricity use to agricultural use by the local community.

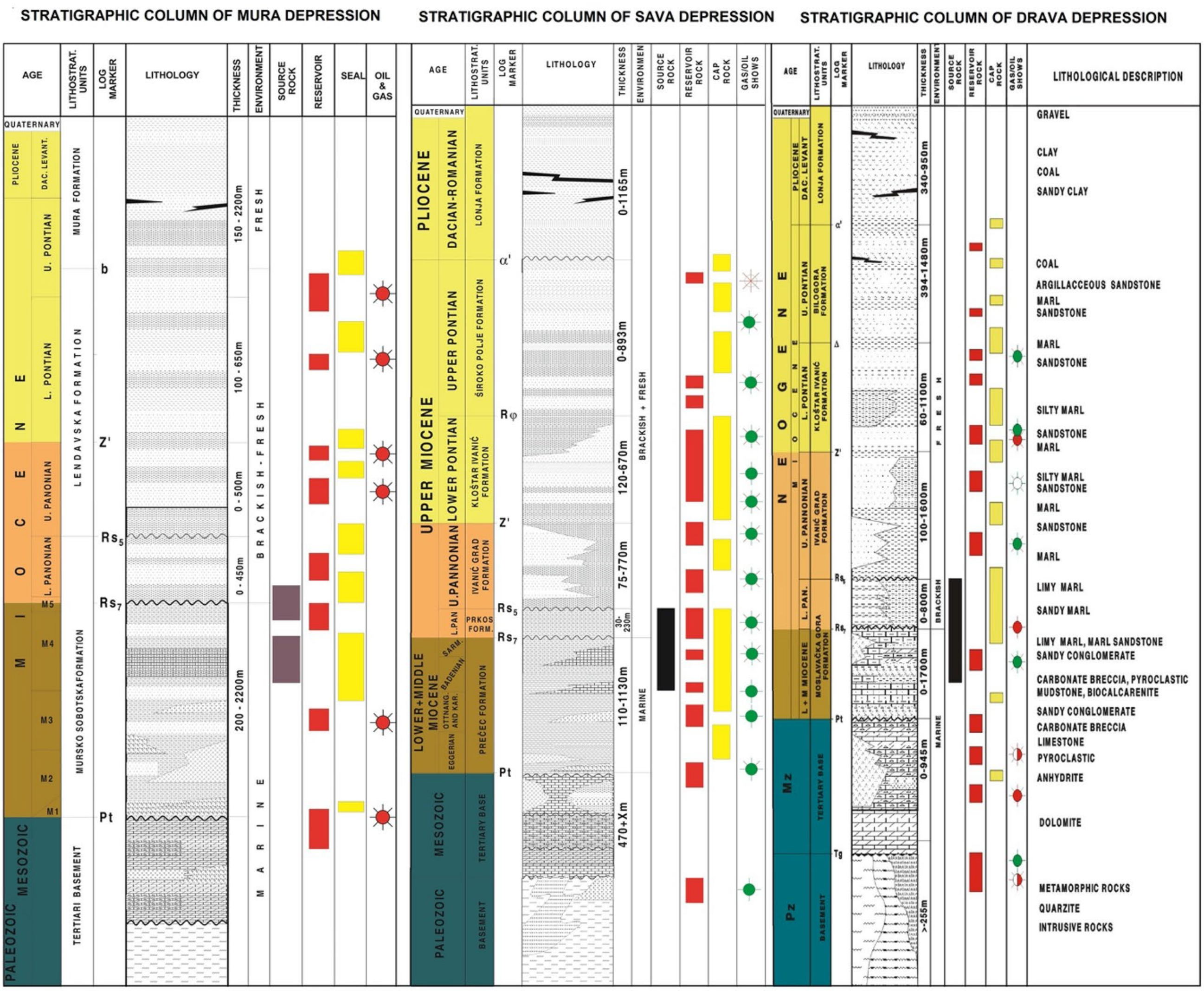


Fig. 5 General geological column of the Mura, Drava and Sava depressions (Durn and Krpan 2016)

In mid-2020, a tender round was announced in the Republic of Croatia for four exploration areas—Legrad-1, Merhatovec, Lunjkovec–Kutnjak and Ernestinovo. Licenses have been issued for all four areas, and exploration activities are planned for the next five years that will lead to the use of geothermal water for energy purposes.

Korenovo exploration block

At the end of 2020, a bid round was carried out for the *Korenovo exploration block* (Fig. 8), which is located in the area of the town of Bjelovar, in the southwest part of the Drava depression. The exploration permit was granted in early 2021 to a company established by the local municipality. It is planned to use the geothermal water for district heating, i.e. for heating of the planned sports and recreation centre and the industrial zone. The geothermal potential of the Korenovo area was discovered in the late 1950s through the construction of the Korenovo-1 (Kor-1) exploration well (Fig. 9). The Korenovo-1 well was also drilled for the purpose of hydrocarbon exploration. The well was not tested as no hydrocarbon phenomena were observed during drilling and geological monitoring of the well. However, during geological monitoring of the well, flooded layers of Neogene sands were found in places. The salinity of the water in these layers is about 8.0 g NaCl/l, while in the permeable interval of lithothamnium limestones the salinity of the water is about 20.0 g NaCl/l. The final depth of the well is 1,457.9 m with a measured temperature of 67.0 °C at the bottom of the well. The average geothermal gradient of the well, based

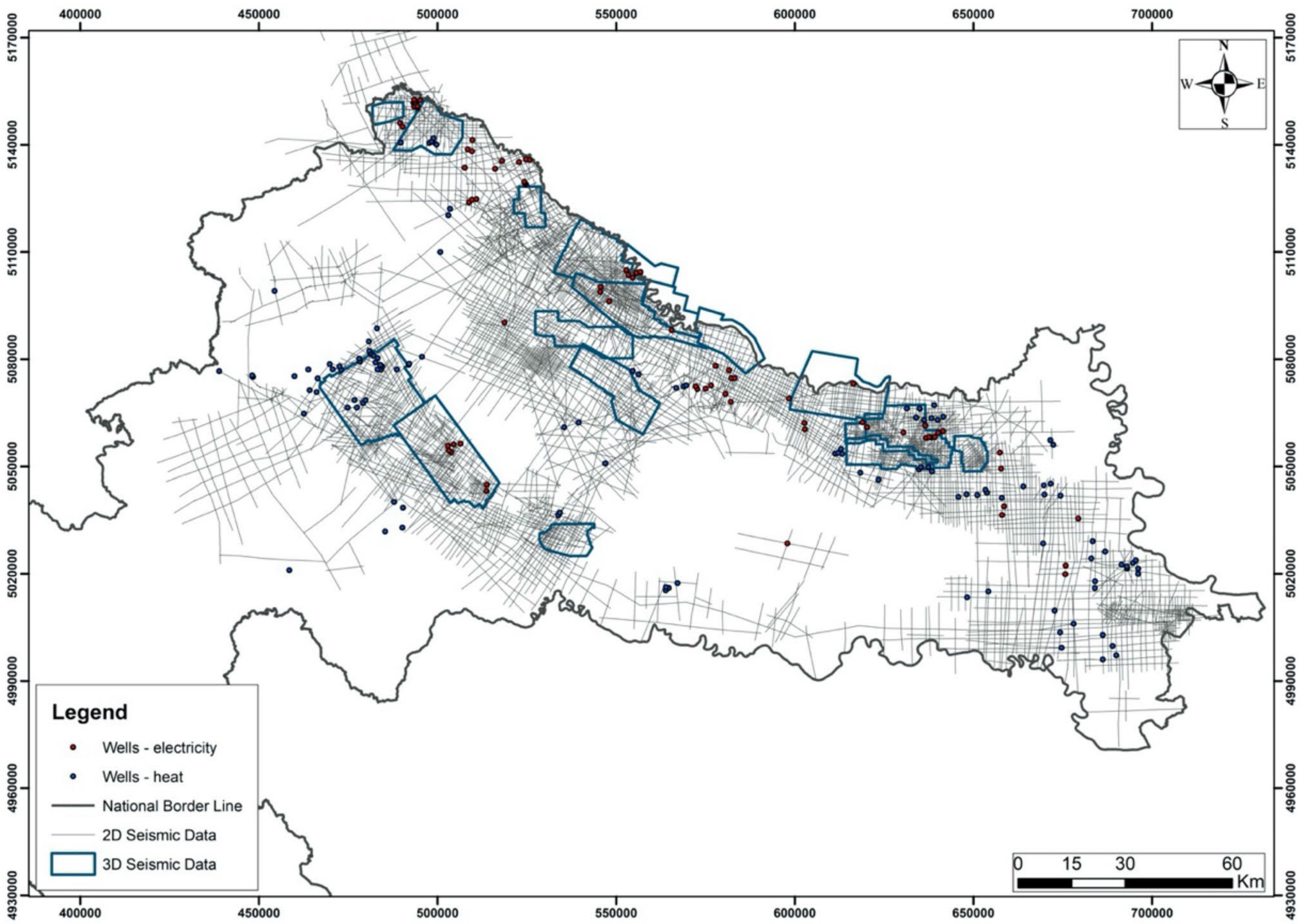


Fig. 6 Existing 2D and 3D seismic data from hydrocarbon exploration available for geothermal reservoirs exploration

on which the exploration area was estimated, is 0.039 °C/m (Croatian Hydrocarbon Agency, 2020a).

Virovitica and Slatina exploration blocks

There are currently 3 exploration blocks in Virovitica-Podravina County—*Virovitica 2, Slatina 2 and Slatina 3*. Exploration permits for Slatina 2 and Slatina 3 exploration blocks were granted in 2018, while Virovitica 2 was granted a permit in February 2020. All three exploration blocks are in the central part of Drava depression. The potential for the Virovitica 2 exploration block was determined based on 6 exploration wells in the vicinity of the exploration block and on 269 km of existing 2D seismic profiles. The temperature of the geothermal reservoir is assumed to be 70.0 °C at a depth of approximately 1,600.0 m. The exploration blocks are licensed to the company formed by the local community and aims to heat business premises in the existing commercial zone and use geothermal water to heat greenhouses (Croatian Hydrocarbon Agency 2019a). Welltesting in the wells of the Slatina 2 exploration block has identified geothermal water reserves with a potential flow rate of 250.0 l/s and a well temperature of 186.0 °C. Future activities in this exploration block will focus on the construction of additional wells, and the possibility of producing electricity, as the reservoir has an extremely high enthalpy. There are two wells on Slatina 3, and the measured temperature at a depth of 4,500.0 m was 191.0 °C. By analysing the data from wells in both exploration areas, we can conclude that the geothermal potential is associated with pre-Neogene pre-rift carbonate deposits (Fig. 10) (Croatian Hydrocarbon Agency 2018).

Križevci exploration block

The *Križevci exploration block* is located in Koprivnica–Križevci County in the Drava depression where exploration activities started in the early 2020. Based on the data from the well, the temperature is estimated to be 74.0 °C at a depth of 1,496.0 m in the limestone, sandstone and breccia complex. During the testing of the well, a

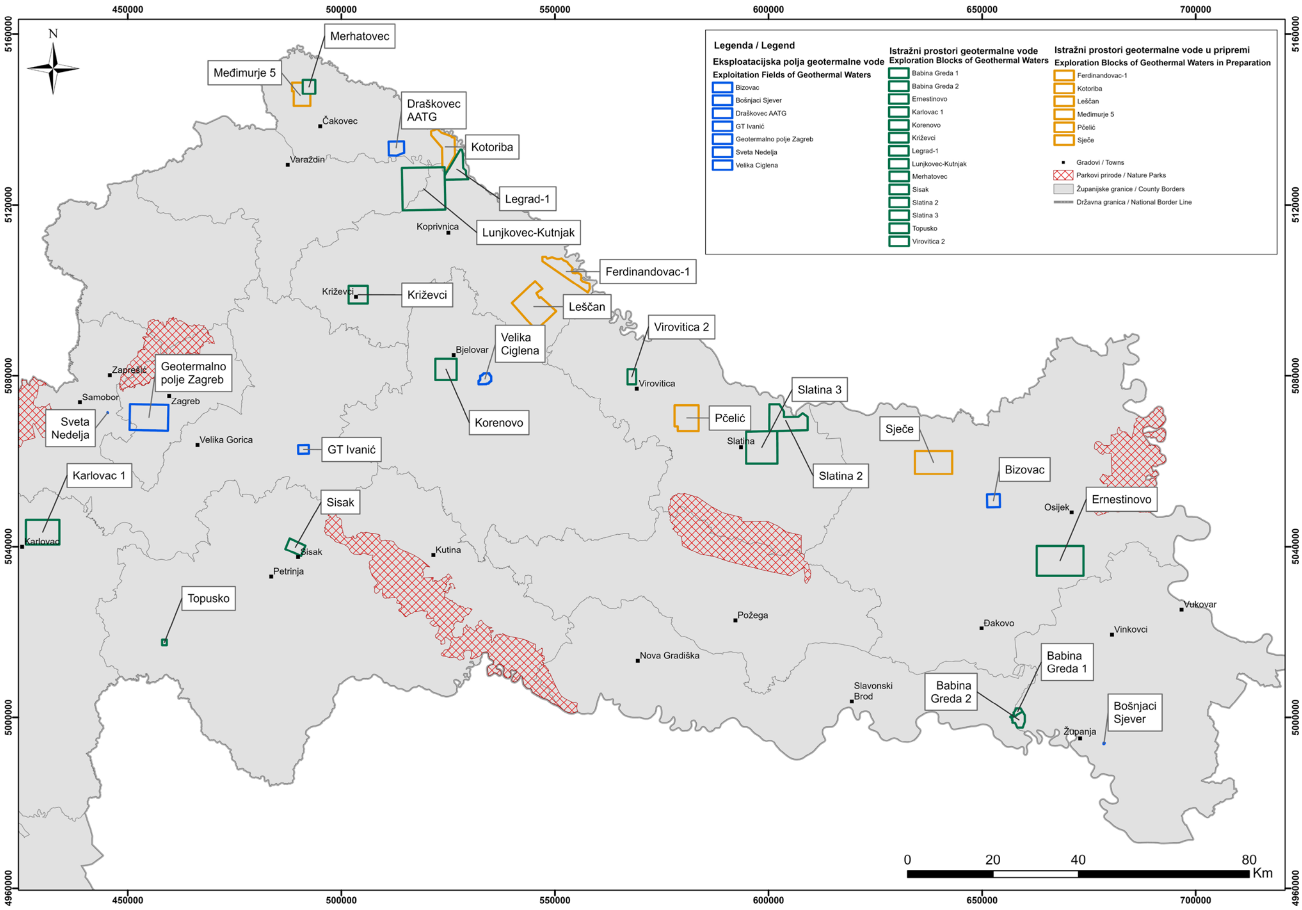


Fig. 7 Exploration blocks and exploitation fields of geothermal water in the Republic of Croatia (Croatian Hydrocarbon Agency 2020a, b, c, d, e)

flow rate of 3.2 l/s was obtained. As the exploration area is located in the town of Križevci, the geothermal water will be used for heating nearby buildings and sports and recreational facilities (Croatian Hydrocarbon Agency 2019b).

Ernestinovo exploration block

The *Ernestinovo exploration block* is located in the southeastern part of the Drava depression (Fig. 11). The geothermal potential of the Ernestinovo area was also discovered during the construction of deep exploration wells for hydrocarbons–Ernestinovo-2 (Ern-2) and Ernestinovo-3 (Ern-3). Drill Stem Testing (DST) was conducted at both wells, and water was obtained from the reservoir (Table 1). The syn-rift carbonate geothermal play lithologically consists of: conglomerates, breccias, marlitic sandstones, calcitic sandstones, lithothamnium limestones (lithuanians), calcitic marls, clay marls, and their variants (Fig. 12). In the Ern-2 well, a temperature of 165.0 °C was measured at a depth of 3,790.0 m, while in the Ern-3 well, a temperature of 125.5 °C was measured at the bottom of the well at a depth of 3,106.0 m (Croatian Hydrocarbon Agency 2020b).

Merhatovec exploration block

The *Merhatovec exploration block* is located in northwestern Croatia and belongs to the Mura depression (Fig. 13). The geothermal potential was determined by testing of two wells—Merhatovec-1 (Mer-1) and Merhatovec-2 (Mer-2)—and the measured temperature during logging at a depth of 4,195.0 m was 150.0 °C, and at a depth of 3,404.0 m was 140.0 °C. The well testing determined the

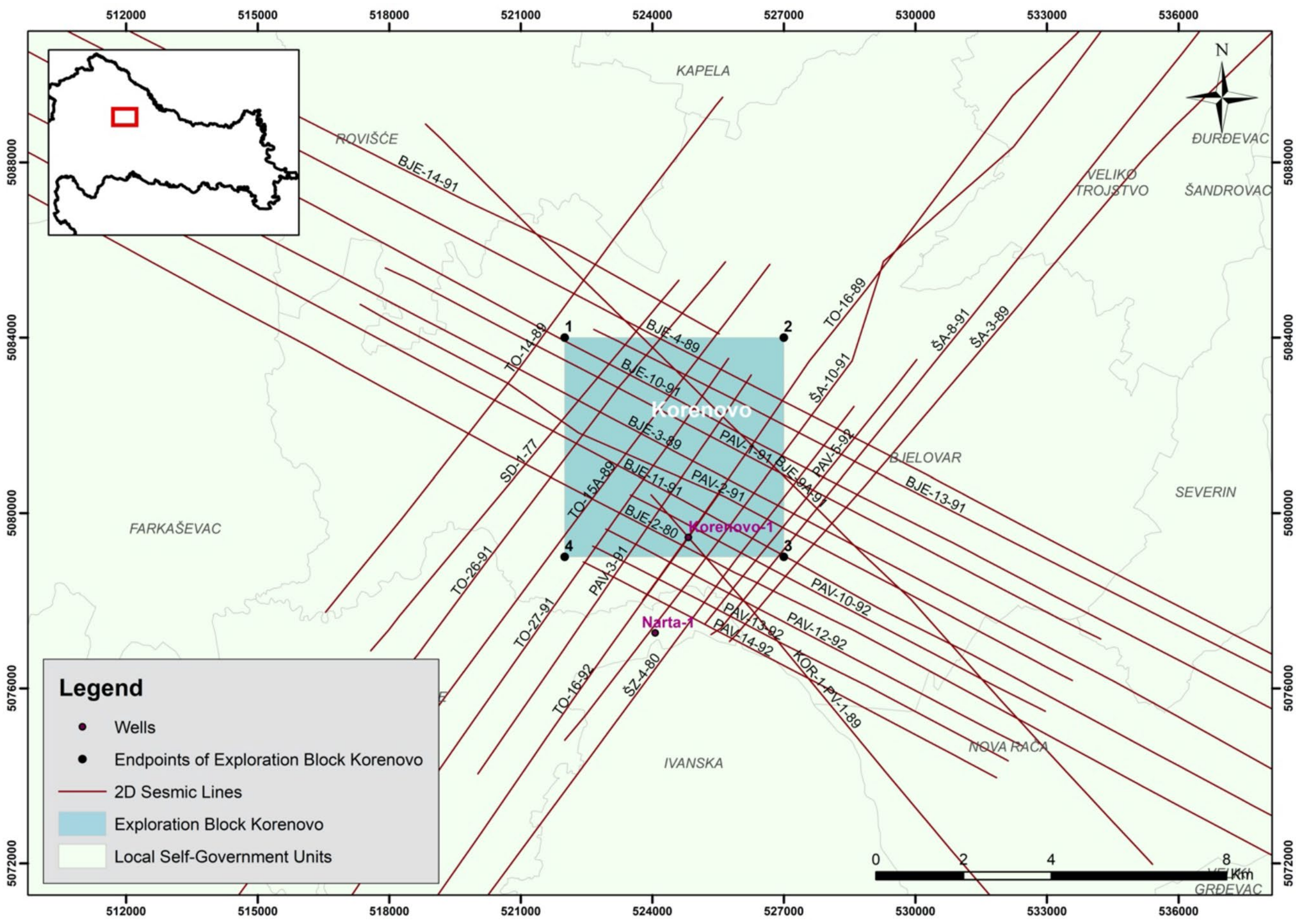


Fig. 8 Exploration block Korenovo (Croatian Hydrocarbon Agency 2020a)

geothermal potential (Table 2) in pre-rift dolomite breccias in the pre-Neogene basement (Fig. 14) (Croatian Hydrocarbon Agency 2020e).

Legrad exploration block

The Legrad-1 exploration block is located at the edge of the northwestern part of the Drava depression and partially overlaps with the Legrad hydrocarbon field (Fig. 15). Legrad geothermal play was determined in pre-Neogene pre-rift carbonates of Mesozoic. The area of the Legrad-1 exploration block is mostly covered by 2D seismic lines, the oldest of which date back to the 1970s, while the most recent ones are from 2016. The area was estimated based on six local wells that revealed the presence of geothermal potential in the complex of dolomite breccias that underlie the Neogene deposits (Fig. 16). The depth of wells ranges from 1,975.0 m to 4,600.0 m, and the temperatures measured at the bottom of the wells range from 105.0 to 212.0 °C, with initial test results seen in Table 3. (Croatian Hydrocarbon Agency 2020c).

Lunjkovec–Kutnjak exploration block

The *Lunjkovec–Kutnjak exploration block* is located in the northwestern part of the Drava depression (Fig. 17). In estimating the geothermal potential of the Lunjkovec–Kutnjak exploration block, data from 9 surrounding wells were considered. Wells were drilled in the 1970s and early 1980s for the purpose of hydrocarbon exploration. The final depths of the wells are 2,203.0 and 2,430.0 m, respectively, with measured temperatures at the bottom of the wells in the range of 128.0 °C to 144.6 °C, and the average geothermal gradient in the area is approximately 0.043 °C/m. The geothermal potential was determined by well testing (Table 4) in the pre-Neogene pre-rift carbonate-clastic complex (Fig. 18) (Croatian Hydrocarbon Agency 2020d). As the Lunjkovec–Kutnjak exploration block is located in an agricultural

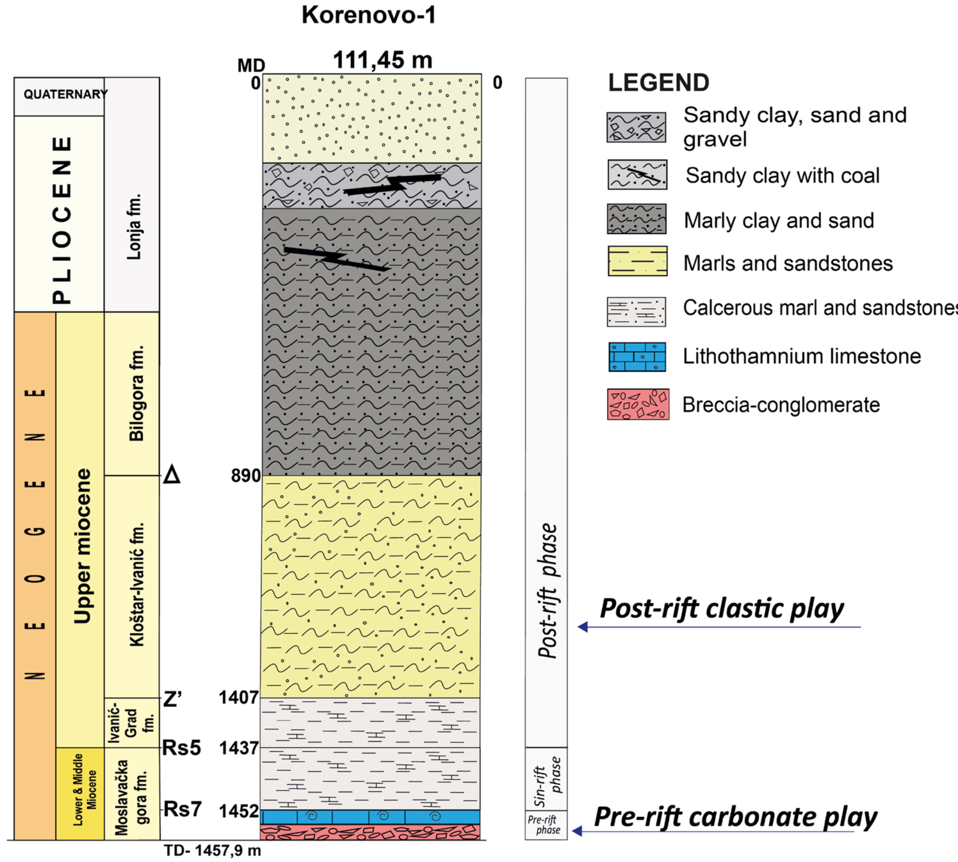


Fig. 9 Schematic lithostratigraphic column of Korenovo-1 well in the Korenovo exploration block (Croatian Hydrocarbon Agency 2020a)

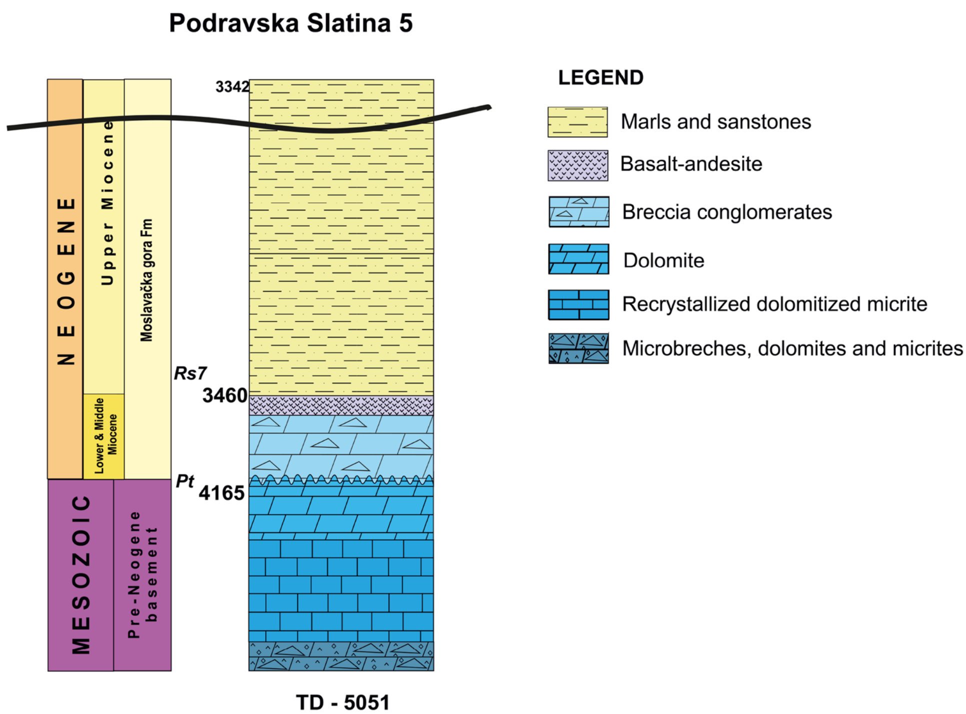


Fig. 10 Schematic lithostratigraphic column of Podravska Slatina-5 well in the Slatina 2 exploration block (Croatian Hydrocarbon Agency, 2018)

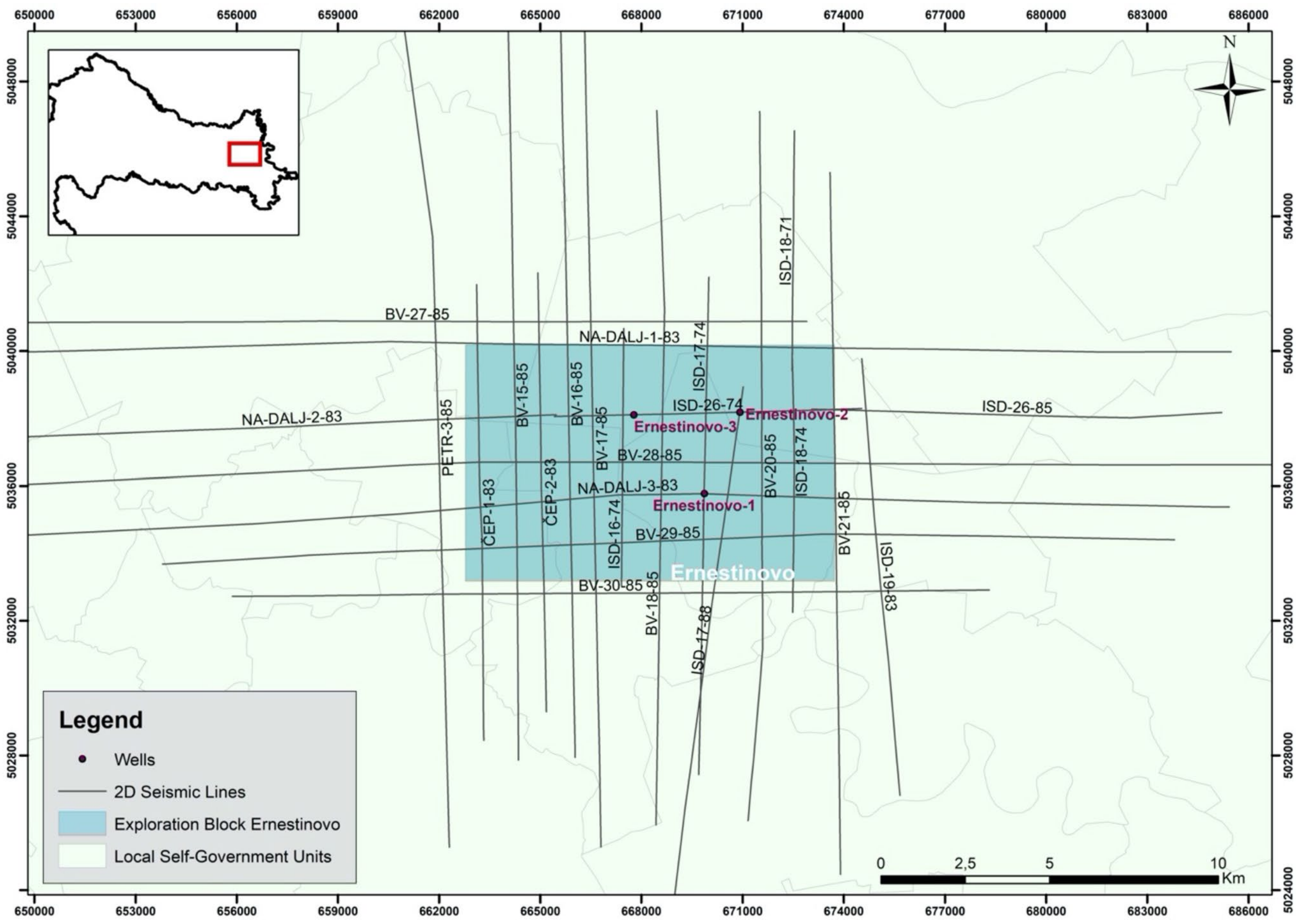


Fig. 11 Exploration block Ernestinovo (Croatian Hydrocarbon Agency 2020b)

area, cogeneration is planned for space heating, electricity generation and greenhouse heating. The estimated electricity generation by the ORC process in the Lunjkovec–Kutnjak exploration area is 2,259.0 kW gross at a flow rate of 34.3 kg/s (Guzović et al. 2012).

Babina Greda exploration blocks

The *Babina Greda 1 and Babina Greda 2 exploration blocks* are located in the easternmost part of the Republic of Croatia, in the Slavonia-Srijem depression. The entire area has been the subject of exploratory drilling as part of hydrocarbon exploration (Fig. 19). In the Babina Greda 1 exploration block, there are three wells, based on which the area was assessed as having geothermal potential. The drilling data and measurements in wells divide the reservoir into the upper part with a temperature of 122.5 °C at a depth of 2,270.0 m, to the deeper part of the reservoir, where temperatures of 161.0 °C were recorded at a depth of 3,802.0 m. No drilling data are available for Babina Greda 2, but based on seismic data the same reservoir development as in the neighbouring exploration block and the same temperature gradients are expected. Permits for these exploration blocks were granted in 2019.

Table 1 Test results of Ernestinovo-2 and Ernestinovo-3 wells

	Ernestinovo-2	Ernestinovo-3
Well depth (m)	3,790.0	3,106.0
Bottomhole temperature (°C)	165.0	125.5
Tested interval (m)	2,932.0–2,888.0	2,603.0–2,584.0
Temperature (°C)	120.0	132.2
Initial tested flow (m^3/day)	15.0	184.8

Karlovac exploration block

The *Karlovac 1 exploration block* is located in the southwestern part of the Karlovac Valley in the immediate vicinity of the town of Karlovac. As there are no wells in the exploration area, correlation was made with wells in the vicinity, Ka-2 and Ka-3. The data from the wells, located

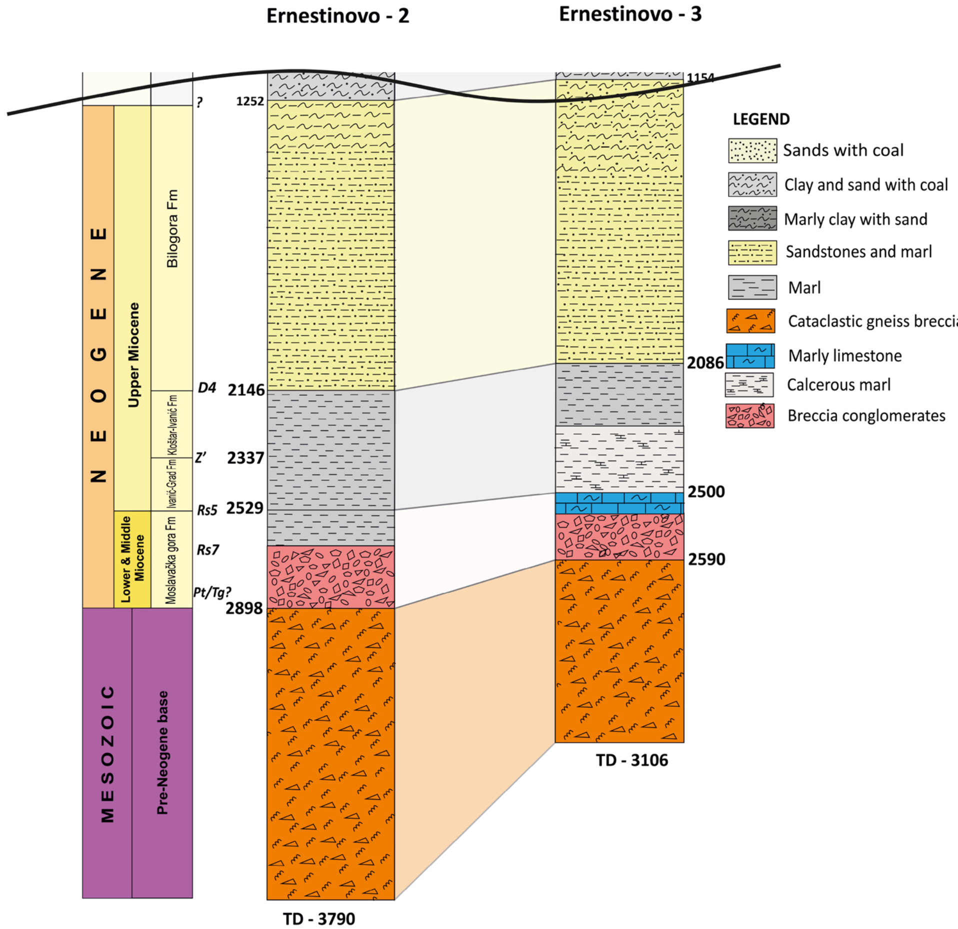


Fig. 12 Schematic lithostratigraphic column of Ernestinovo-2, Ernestinovo-3 wells in the Ernestinovo exploration block (Croatian Hydrocarbon Agency 2020b)

near the northeast corner of the exploration block, showed the existence of a bottom aquifer with a temperature of 139.0 °C, measured at a depth of 4,145.0 m. Since the area is close to the city of Karlovac, which has a developed district heating network, the geothermal water would be used for household heating.

Summary of Croatian geothermal exploration blocks

Table 5 presents summarised data for geothermal exploration fields described in detail in previous subchapters. Favourable geothermal gradients are determined, with lowest value at 0.031 °C/m at the Karlovac site. Further assessment of the locations is needed, especially in the terms of determining flow possibilities, after which energy potential can be calculated.

Evaluation of energy potential in licensed exploration blocks

Almost all exploration blocks of geothermal water for energy purposes in the Republic of Croatia are in the exploration phase, where the exact qualitative and quantitative parameters have not yet been determined. Once these parameters are available, the exact energy potential of each area, and therefore its purpose with a degree of certanity, could be defined. Based on the available data on the exploration blocks themselves or on data available in the vicinity of the exploration area that proved to be correlative for the analysis, an assessment of the energy potential needs to be made. Moreover, the final decision will depend on the investor and his business plan. For this reason, the assessment of thermal and electrical power in each of the study areas needs to be tackled. As mentioned earlier, the temperature data measured in the reservoir were used as input temperature for determining geothermal potential. The internal investigation of the geothermal potential for each field was relied upon a numerous drill stem tests or production well testing data. All of these exploration fields have a high probability of achieving a flow rate between 10.0 and 100.0 l/s, with an initial setup of one exploitation well and one injection well. This was carried out with petroleum production software and simulation of production according to obtained petrophysical data from well testing in the past. In this way, the unit value of each exploration area was determined, and we

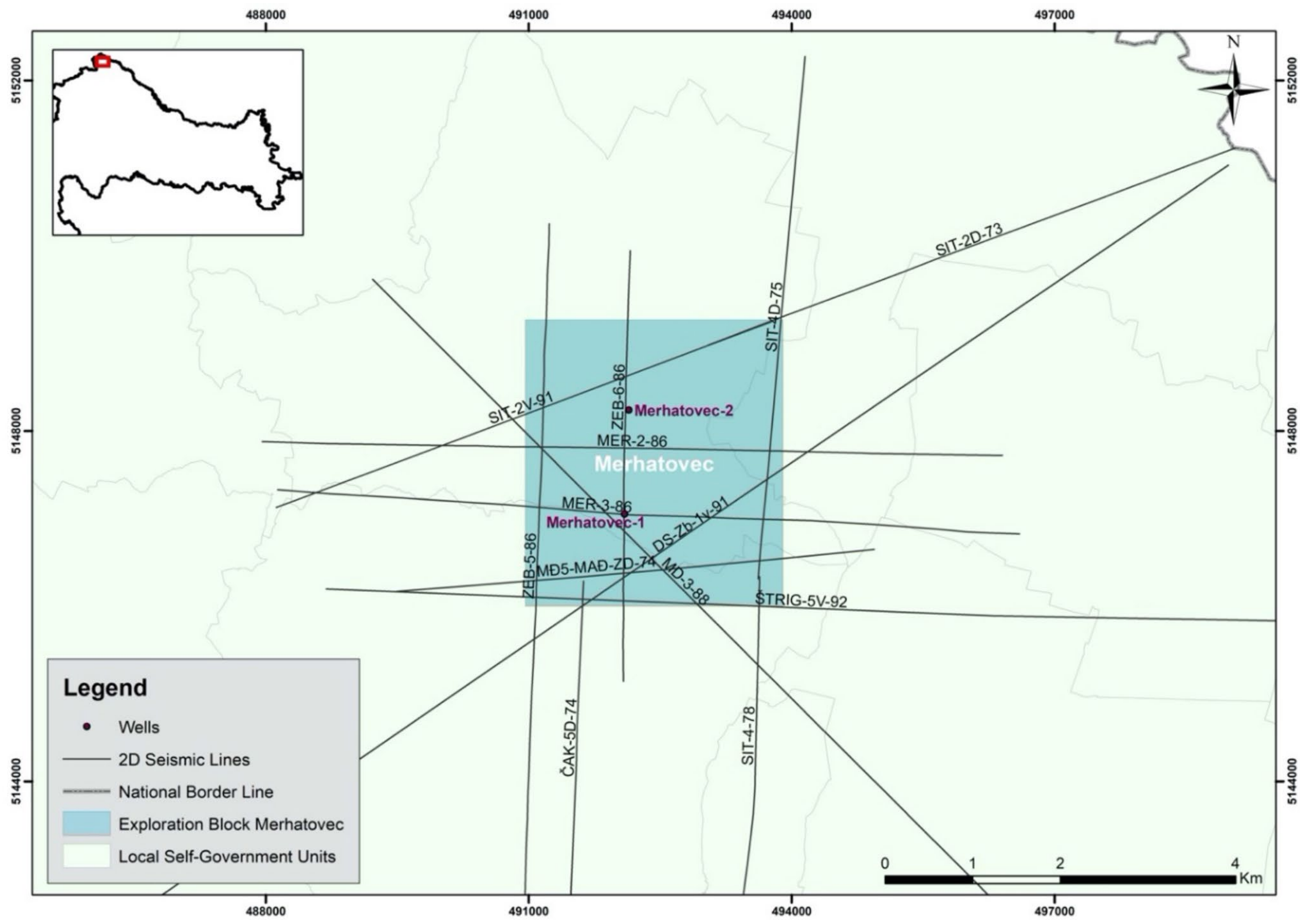


Fig. 13 Exploration block Merhatovec (Croatian Hydrocarbon Agency 2020e)

can assume that the energy availability increases linearly with the number of new development wells. Since, as mentioned above, not all parameters were available at the time of exploitation of the geothermal water, so the temperature of the geothermal water in the reservoir was used as the inlet temperature to the heat exchanger for the first government approximation of potential. According to the Ordinance on Reserves (Official Gazette 95/2018), the classification and categorisation of geothermal waters in the Republic of Croatia are defined. Thus, in case the exit temperature from the reservoir after the heat exchanger is not known, i.e. geothermal waters are not yet categorised into reserves but into contingent resources and the reference water temperature after heat utilisation is set at 30.0 °C and standard pressure values ($p = 1.0$ bar). To estimate the thermal output of the geothermal potential in the exploration blocks as the temperature of the water at the outlet of the heat exchanger for all cases, a temperature of 30.0 °C should be taken. In estimation of the possible electrical power production, 9 exploration blocks were considered because the measured reservoir temperature was higher than 130.0 °C. The temperatures were assumed to be favourable input temperatures in the conversion of geothermal energy into electricity via the binary Organic Rankin System (ORC) (DiPippo 2004).

Table 2 Test results of Merhatovec-1 and Merhatovec-2 wells

	Merhatovec-1	Merhatovec-2
Well depth (m)	4195.0	3404.0
Bottomhole temperature (°C)	150.0	140.0
Tested interval (m)	2405.0–2415.0	2386.85–2399.0
Temperature (°C)	126.7	140.8
Initial tested flow(m^3/day)	937.0	20.0

Geothermal exploitation fields

Ivanić geothermal field

Ivanić geothermal field is a part of the bigger Ivanić oil and gas field. The Ivanić oil and gas exploitation field is located

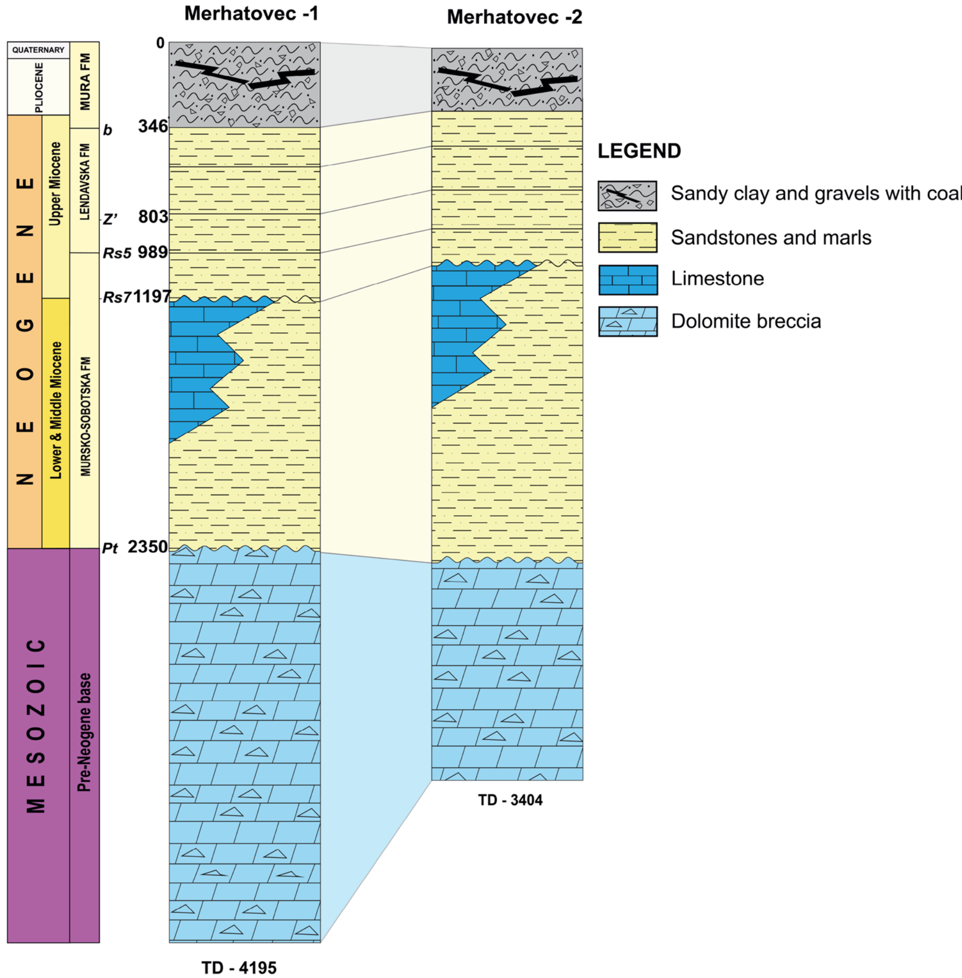


Fig. 14 Schematic lithostratigraphic column of wells Merhatovec-1 (mer-1) and Merhatovec-2 (mer-2) in the exploration block Merhatovec (Croatian Hydrocarbon Agency 2020e)

in the northwestern part of the Sava depression and is one of the oldest oil fields in Croatia. The first exploration work in this area began in 1940 with a regional gravimetric survey and continued in 1954 with seismic surveys. The oil field was discovered in 1959 and hydrocarbon exploitation has been active ever since. In 1962, the presence of reservoir “I” and “K” with water saturation was determined (Fig. 20). The geothermal reservoirs "I" and "K" consist of quartz-mica sandstones with intermediate layers of clay and marl that lie at a depth of 1,200.0–1,300.0 m, varying in thickness between 30.0 and 70.0 m, and belong to Neogene deposit. Reservoirs "I" and "K" are considered unique geothermal reservoir. Based on logging measurements, the porosity of the reservoir is 20.4%, while the interpretation of the hydrodynamic testing showed the permeability of the reservoir to be 94.2 mD. The geothermal gradient of the reservoir is 0.050 °C/m (the average annual temperature of the area is 11.6 °C) (INA-Industrija nafte d.d., 2005). The geothermal waters are produced by production well, Iva-1 T well, while the Iva-2 well is converted to geothermal metering well, with the possibility of conversion to production or injection well, after depletion of the oil reservoir. The exploitation of the Ivanić geothermal filed started in 1988 and at that time production from the well Iva-1 T was eruptive. After the eruption ceased, a deep centrifugal pump with the possibility of pumping up to 492.0 m^3/day was installed in the well. Due to the low demand of the heat users, smaller volumes were produced and the temperature at the wellhead varied between 30.0 and 58.0 °C. The field was produced from a single well and due to low water flows, produced water was injected through the gathering system to the oil reservoir to maintain oil reservoir pressure. The geothermal production potential of the geothermal reservoir "I + K" was estimated based on the production from well Iva-1 T and is 3.0 l/s with the installation of a deep centrifugal pump and with wellhead temperature of 58.0 °C. According to the well flow and the assumed temperature, the installed capacity at ΔT of 28.0 °C is 0.35 MW_t. As the water from this reservoir has

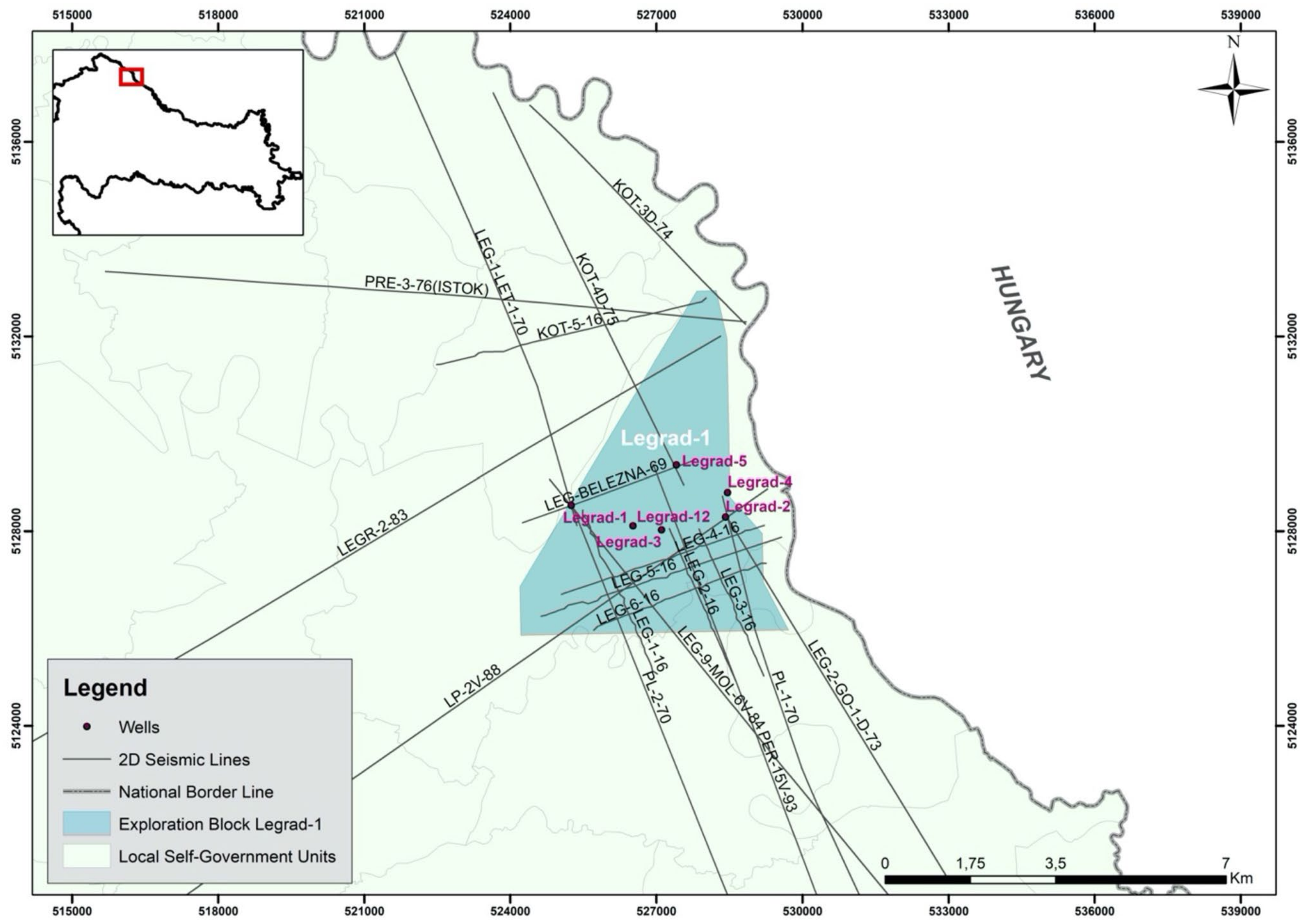


Fig. 15 Exploration block Legrad-1 (Croatian Hyrdocarbon Agency 2020c)

medicinal properties, it was used for balneological purposes in a nearby hospital (INA-Industrija nafte d.d., 2016).

Bizovac geothermal field

The Bizovac geothermal field is located in the eastern part of the CPB and belongs to the Drava depression. The geothermal field was discovered during hydrocarbons exploration activities that began in 1953 with gravimetric measurements and continued in 1954 with seismic surveys. The Bizovac oil field was discovered in 1967 by the Bizovac-1 exploration well. In the same year, two more wells were drilled, and geothermal water reserves were discovered by the Bizovac-2 well (Fig. 21). New wells were drilled, and larger quantities of geothermal water were discovered with the Bizovac-4 well at a depth of 1,761.0 m (INA-industrija nafte 1993a). The geothermal potential is located in two separate reservoirs–the Terme reservoir and the A3 and A4 reservoir. The Terme reservoir is located on the upper part of the basement and is characterised by coarse- and fine-grained breccias, breccia conglomerates and coarse-grained sandstones and is not connected to the oil reservoir. The initial pressure of the Terme reservoir is 208.6 bar, the initial temperature is 111.7 °C at a depth of 1,820.9 m, and the geothermal gradient is 0.055 °C/m. Reservoirs A3 and A4 are located above the oil reservoir and are formed in medium-grained sandstones with a large surface distribution. They are separated from the oil reservoir by up to 100.0 m thick marls and sealed sandstones. Between reservoirs A3 and A4, there is an insulating rock about 15.0 to 25.0 m thick, but the reservoirs are considered to be a unique reservoir of geothermal water with temperature of 103.5 °C at a depth of 1,623.4 m. The geothermal gradient is 0.057 °C/m, and the initial pressure is 159.2 bar. The assumed permeability for the Terme reservoir is 18.6×10^{-3} μm^2, while a permeability of 191.0×10^{-3} μm^2 was assumed for the "A3 + A4" reservoir when analysing the results of hydrodynamic measurements. Three wells are active in the Bizovac geothermal field, namely Bizovac-2 for injection and Bizovac-4 for exploitation in the Terme reservoir, and Slavonka-1 for exploitation of the A3 and A4

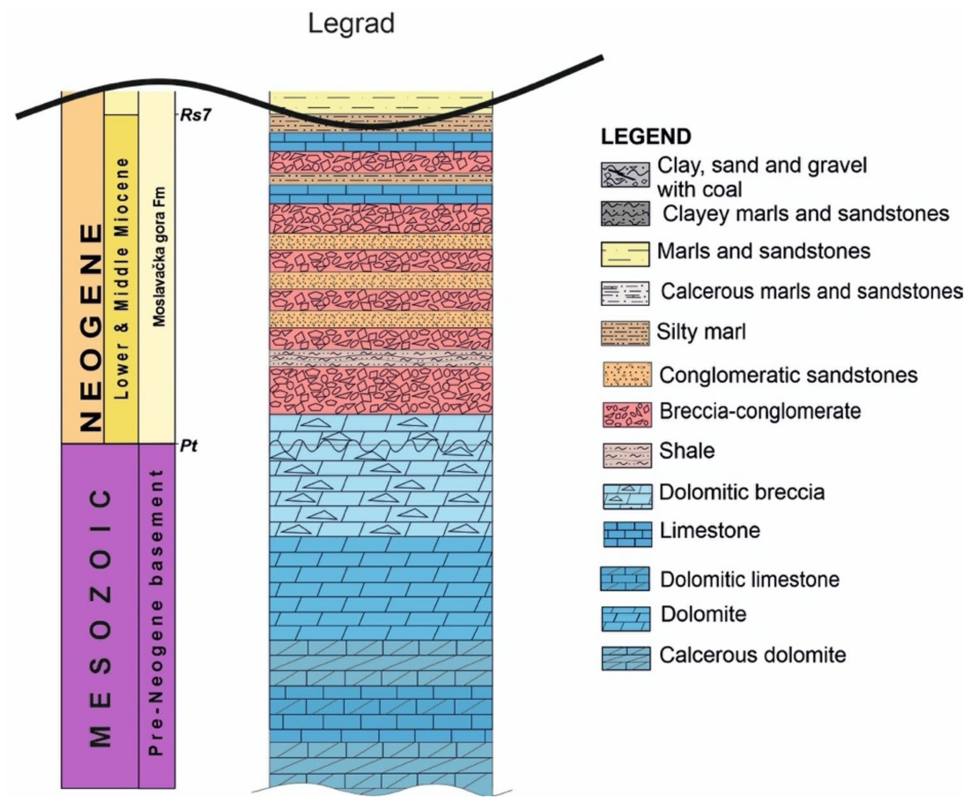


Fig. 16 Schematic general lithostratigraphic column of the Legrad area (Croatian Hydrocarbon Agency 2020c)

reservoirs (Table 6). The proven reserves (1P) of the Bizovac geothermal field are 4.63 l/s and 0.76 MW_t, while the probable (2P) are 7.8 l/s and a thermal output of 1,279.0 MW_t (INA-Industrija nafte d.d 2021). The geothermal water is used for balneological purposes and partly for heating the recreation centre.

Draškovec AATG geothermal field

The Draškovec AATG field is located in northern Croatia in the Mura depression on the border with the Drava depression (Fig. 22). The field was discovered during oil and gas exploration in the 1970s by the Draškovec-1 exploration well, which was drilled in 1977. The bottom temperature (2,710.0 m) of 113.0 °C was measured at the well, and two tests (DST) were performed to obtain water. Near the field, there are several wells drilled in sandstones, lithothamnium limestones or their equivalents and all have confirmed saturation with water and dissolved gas. The same sequence of occurrences was also confirmed in the Draškovec geothermal field. In 2016, a new well, Draškovec-2, was drilled, which confirmed geothermal potential in two reservoirs–shallow sandstone and a deeper limestone reservoir both belonging to Neogene deposits. The measured temperature of the sandstone reservoir at a depth of 2,102.0 m is 105.0 °C with an initial reservoir pressure of 211.0 bar and a geothermal gradient of 0.045 °C/m, while the measured temperature of the limestone reservoir at a depth of 2,274.5 m is 110.0 °C, the initial reservoir pressure is 229.4 bar and the geothermal gradient is 0.044 °C/m. Significant amounts of dissolved gas were encountered during well testing, ranging from 2.62 m^3/m^3 in the sandstone reservoir to 2.89 m^3/m^3 in the limestone reservoir. An increased amount of carbon dioxide was also detected in the composition of the gas. Due to the peculiarity of the reservoir and the large amount of dissolved gas and the presence of CO_2 in the gas, the development of the field and the use of geothermal energy are planned in the innovative sense. The project intends to separate the natural gas from the brine, use it in gas turbine for electric power while the CO_2 is collected at the exhaust and injected into the reservoir. The geothermal brine would be used in cogeneration cycle–electricity

Table 3 Test results of exploration block Legrad-1

	Legrad area
Tested interval (m)	3,515.0–3,531.0
Temperature (°C)	190.0
Initial tested flow (m^3/day)	432.0

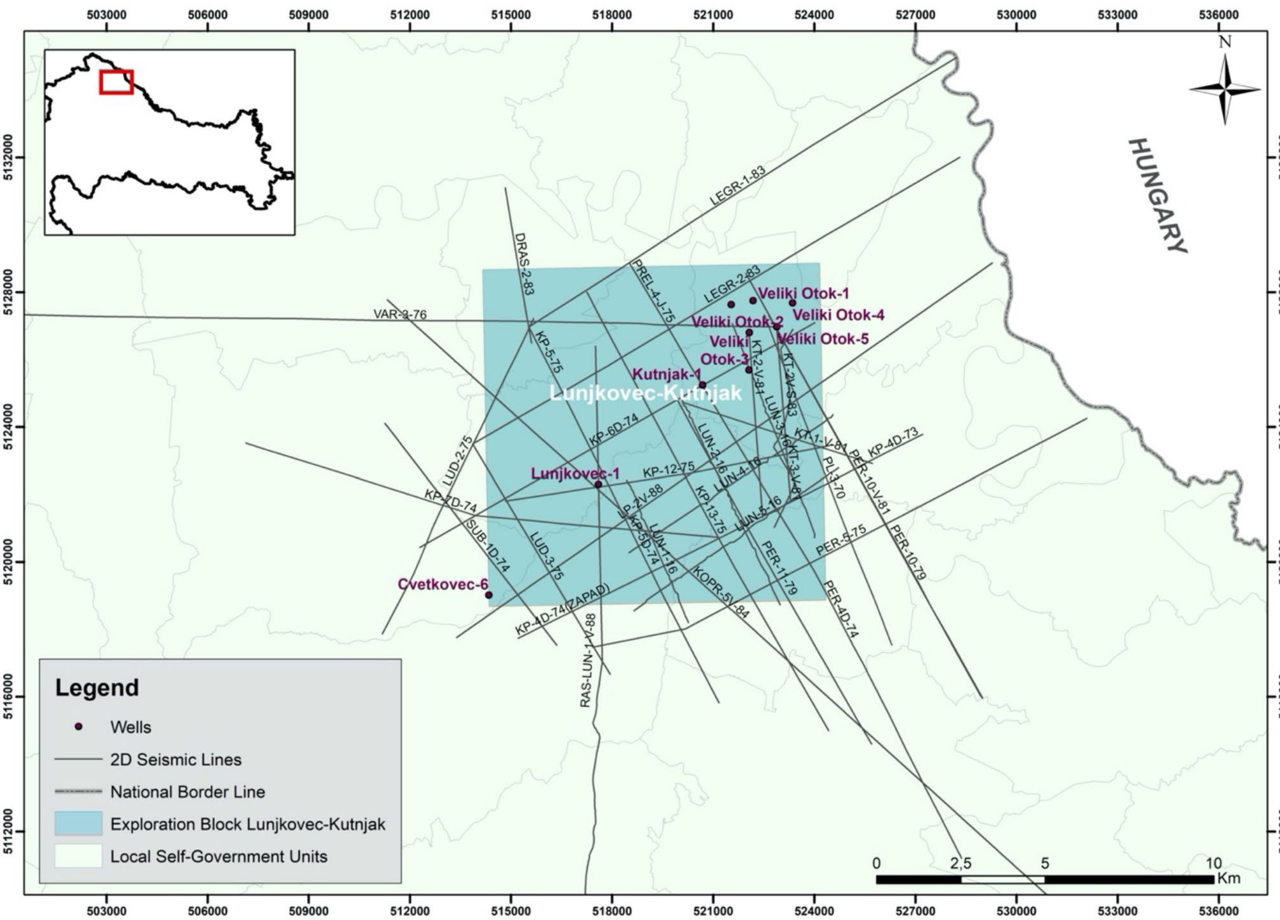


Fig. 17 Exploration block Lunjkovec–Kutnjak (Croatian Hydrocarbon Agency 2020d)

Table 4 Test results of Lunjkovec-1 and Kutnjak-1 wells

	Lunjkovec-1	Kutnjak-1
Well depth (m)	2203.0	2430.0
Bottomhole temperature (°C)	128.0	144.6
Tested interval (m)	1729.0–1755.0	2166.0–2430.0
Temperature (°C)	120.0	95.0
Initial tested flow (m^3/day)	322.9	685.0

generation in a ORC power plant and space heating after the brine leaves the binary system. The project for the development of the AATG Draškovec geothermal field envisages the construction of four pairs of injection and production wells, which will generate electricity and heat the sports and recreation centre with surplus thermal energy (AAT Geothermae Ltd 2017). The 2016 reserves study shows the probable reserves (2P) of 52.1 l/s and thermal capacity of 13.0 MW_t (AATG Geothermae Ltd 2016).

Sveta Nedelja geothermal field

The Sveta Nedelja exploitation field (Fig. 23) completed its exploration activities and began the exploitation of the geothermal brine. The exploitation license was obtained in 2021. The reserves of 25 l/s were determined (Eko Plodovi, Ltd., 2018). Geothermal water is used for agricultural purposes, e.g. for hydroponic tomato cultivation. There is one exploitation well in the block, which measured temperatures of 61.4 °C at a depth of 777.0 m. By extrapolating the data, it is assumed that the temperature at 1,056.0 m is 71.5 °C, with a wellhead temperature of 65.0 °C at a flow rate of 25.0 l/s. The geothermal gradient is then at 0.056 °C/m.

Bošnjaci-North geothermal field

The Bošnjaci-North geothermal field is in the very east of Croatia in the Slavonia-Srijem depression (Fig. 24). The field was discovered during the drilling of the exploration well Bošnjaci-1 in 2011. The geothermal reservoir is a lithofacies of water-saturated sandstone at a depth of

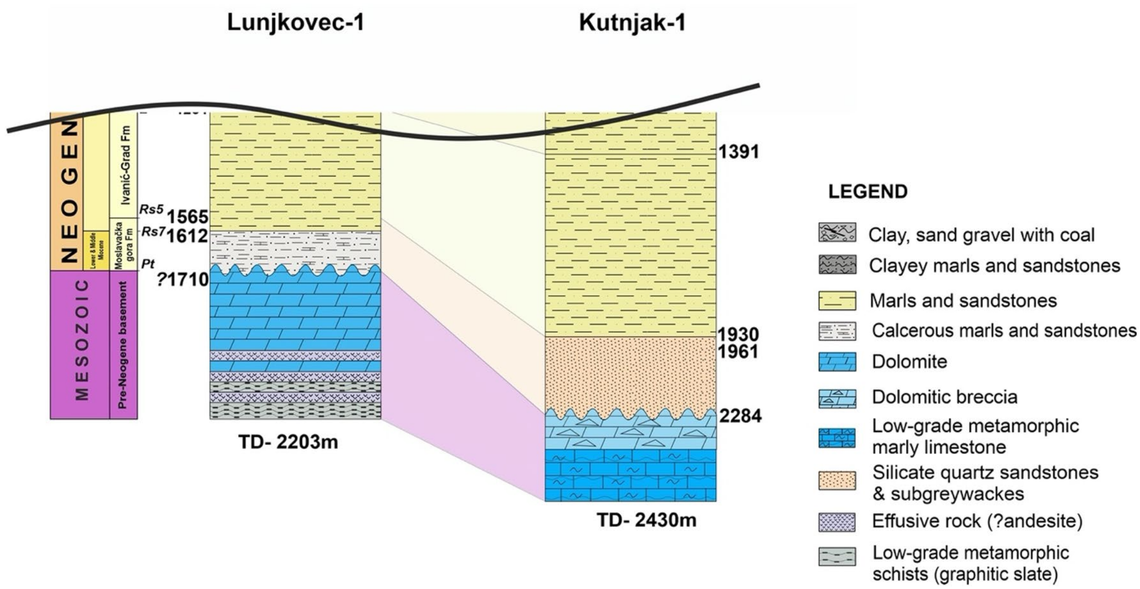


Fig. 18 Schematic lithostratigraphic column of wells Lunjkovec-1 and Kutnjak-1 (Croatian Hydrocarbon Agency 2020a, b, c, d, e)

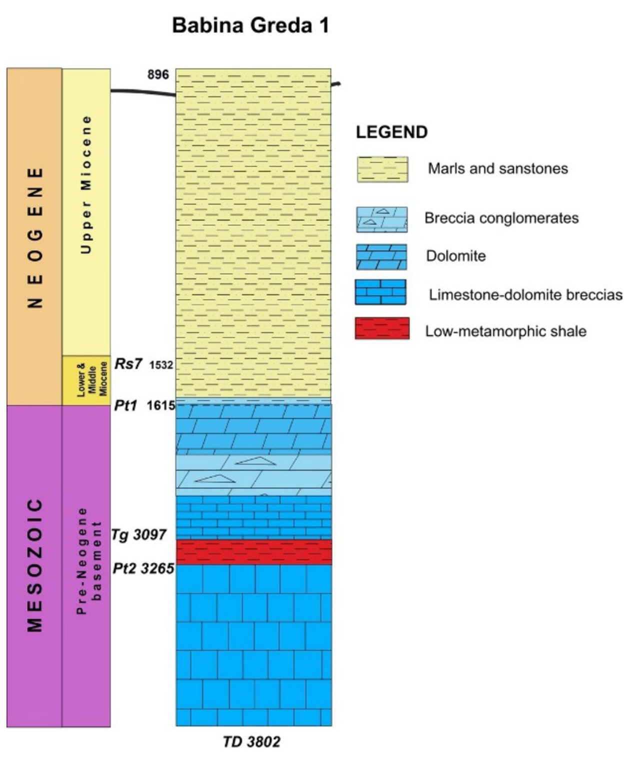


Fig. 19 Schematic general lithostratigraphic column of the Babina Greda area (Croatian Hydrocarbon Agency 2019c)

782.0 m to 1,035.0 m. The temperature of the reservoir is 73.3 °C at a depth of 1,020.0 m, and the geothermal gradient is 0.060 °C/m. The porosity of the reservoir is 22.0%, and the permeability was determined by interpretation of hydrodynamic measurements and is 233.0×10^{-3} μm^2. In the wider area, previous exploration activities have identified geothermal water resources in the deeper carbonate rocks of the pre-Neogene age with secondary pore space, but in the Bošnjaci-North exploitation field a satisfactory and economically achievable target for exploration is a sand reservoir belonging to Neogene sediments. In fact, the well was made for the purpose of heating the greenhouse for hydroponic tomato cultivation, and the temperatures of 65.0 °C at the wellhead and the possible supply of 20.0 l/s were sufficient for the planned use. The geothermal water is used through

Table 5 Summarised data of geothermal exploration fields in Croatia

Exploration field	Number of analysed wells	Average geothermal gradient (°C/m)	Flow (l/s)
Korenovo	1.0	0.039	–
Virovitica 2	–	0.036	–
Slatina 2	–	–	250.0
Slatina 3	2.0	0.040	–
Križevci	1.0	0.042	3.2
Ernestinovo	2.0	0.039	0.2–2.1
Merhatovec	2.0	0,036	0.2–10.8
Legrad	7.0	0.050	5.0
Lunjkovec–Kutnjak	8.0	0.043	34.3
Babina Greda	3.0	0.044	–
Karlovac	2.0	0.031	–

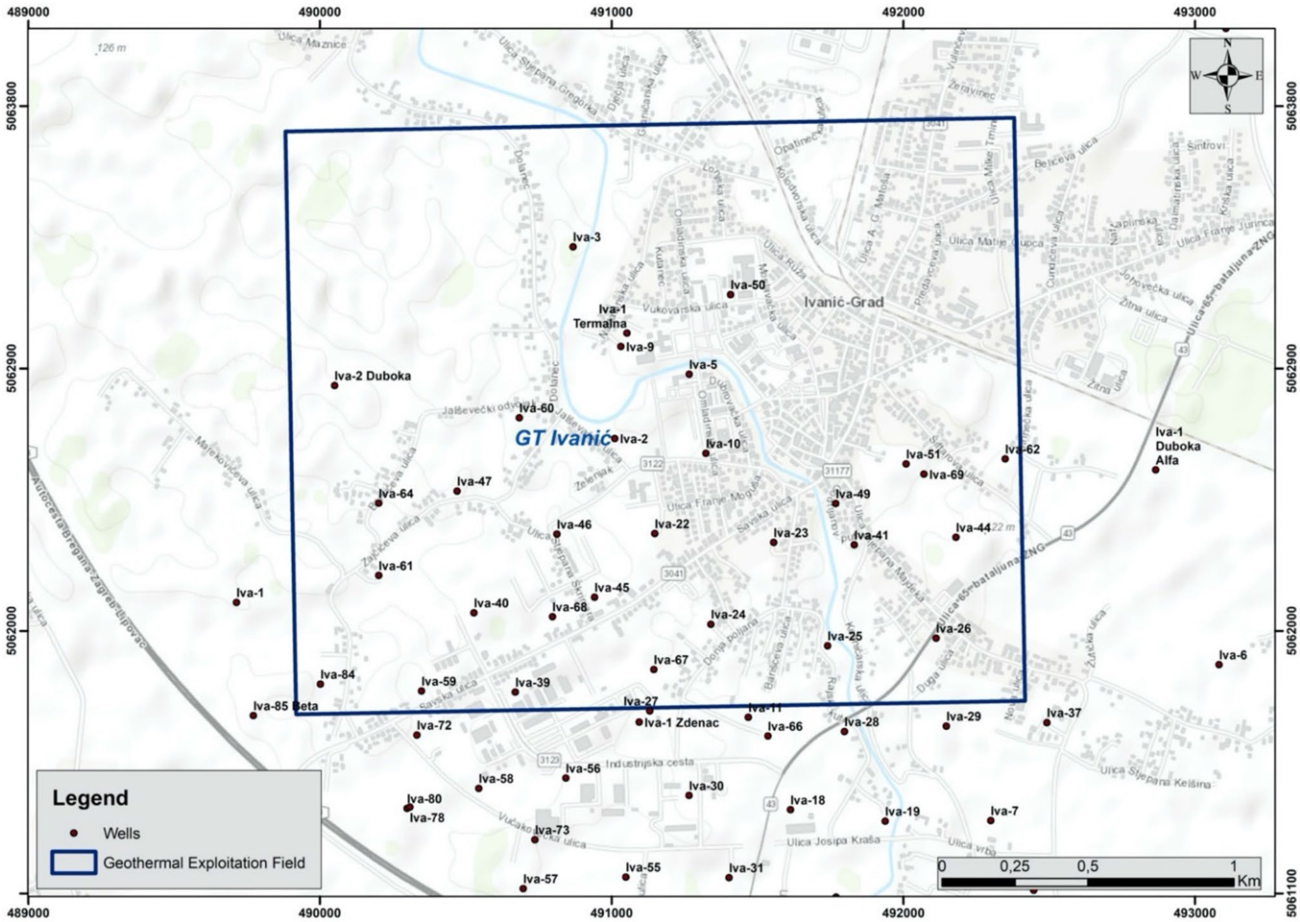


Fig. 20 Geothermal exploitation field Ivanić

a single well, while the return water is discharged into the drainage canal, which is possible due to the water quality. The proved (1P) geothermal water reserves are 10.0 l/s, and the installed thermal capacity is 1.4 MW_t (Ruris 2018).

Zagreb geothermal field

The first well drilled in the area of the Zagreb geothermal field was Stupnik-1 in 1964. The well was drilled for oil exploration but proved negative and was therefore abandoned. New hydrodynamic tests on the well, which followed in 1977, revealed water saturation at a depth of 733.0 to 815.0 m with a temperature of 57.0 °C. The entire geothermal field is located in the area of the city of Zagreb and belongs to the wider area of the Sava depression (Fig. 25). After testing the first well, further exploration activities and interpretation of seismic data began, and on this basis the second geothermal well–Mladost-1 was drilled in 1980. The well was producing eruptive and delivered 3.4 l/s with wellhead temperature of 70.0 °C. In the following years, further wells were drilled, of which there are currently 15. The Zagreb geothermal field was formed in the pre-rift pre-Neogene basement, which consists mostly of dolomites with good storage properties, the thickness of which is up to 200.0 m. Their thickness increases towards the west of the reservoir while in the north and northeast direction they significantly protrude or sink. The basement, which was drilled with the Stupnik-1, KBNZ-2, KBNZ-3 and KBNZ-3B wells, forms the bottom of a geothermal reservoir and consists of impermeable rocks, gneisses, shales and clay slates. The reservoir is characterised by high flow capacity, especially in the central part of the field around the Mladost-3 and KBNZ-1B wells, as well as declared heterogeneity in vertical and areal terms. Porosity of the reservoir is from 6.13 to 14.5% (INA-Industrija nafte 1993b). The initial reservoir pressure

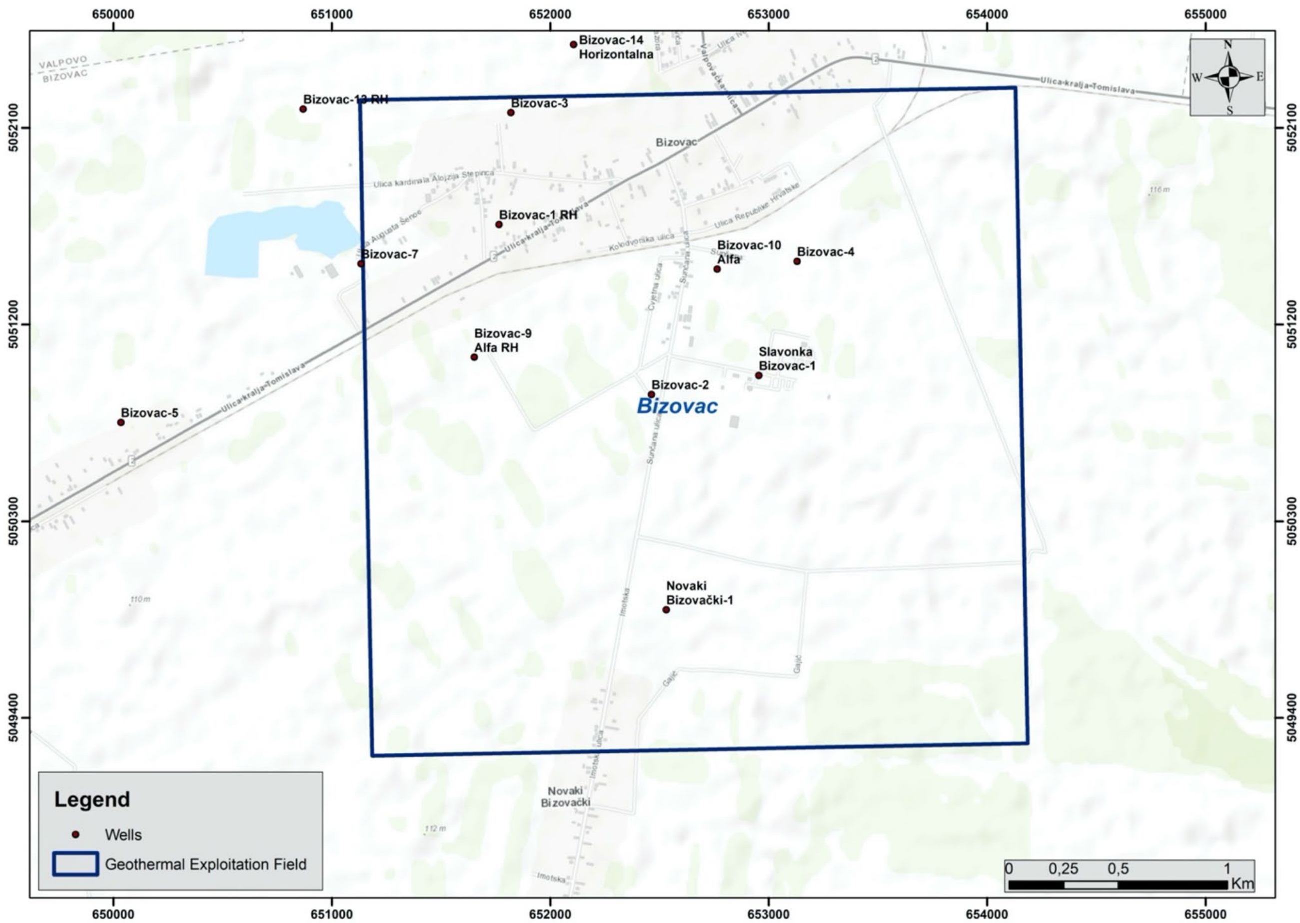


Fig. 21 Geothermal field Bizovac

Table 6 Well status—Bizovac geothermal field

	Well	Depth (m)	Status
1	Bizovac-2	1,862.0	Injection
2	Bizovac-4	1,866.0	Production
3	Slavonka-1	1,668.0	Production

is 104.0 bar at a reference reservoir depth of 979.0 m, and the initial reservoir temperature was 75.0 °C, derived from measurements at the Mladost-1 well. Since most of the production in the geothermal field is performed from wells from the warmest part of the reservoir, a temperature of 80.0 °C was adopted as the initial temperature for the calculation of the reserves. Later measurements confirmed a temperature of more than 80.0 °C at the KBNZ-1B and Mladost-1, and the presumed reason for this is probably the large vertical permeability around these wells and the significantly faster heat transfer. Table 7 shows wells with corresponding depth and recorded bottom temperatures within the geothermal field Zagreb, as well as their status. The geothermal gradient of the Zagreb field is between 0.050 and 0.053 °C/m, at the marginal wells and in the central part of the field between 0.057 and 0.078 °C/m. Proven reserves (1P) of the Zagreb geothermal field amount to 6.2 l/s and installed thermal capacity of 1.3 MW_t, while probable reserves (2P) at a flow rate of 77.1 l/s amount to 15.7 MW_t of installed thermal capacity (GPC Instrumentation process Ltd., 2018). Exploitation in the Zagreb geothermal field is carried out through technological systems on three locations—the Mladost site, the Blato site (KBNZ) and the Lučko site (Cazin and Jurilj 2019). The technological system of the Mladost site consists of an injection well (Mla-2) and a production well (Mla-3) and

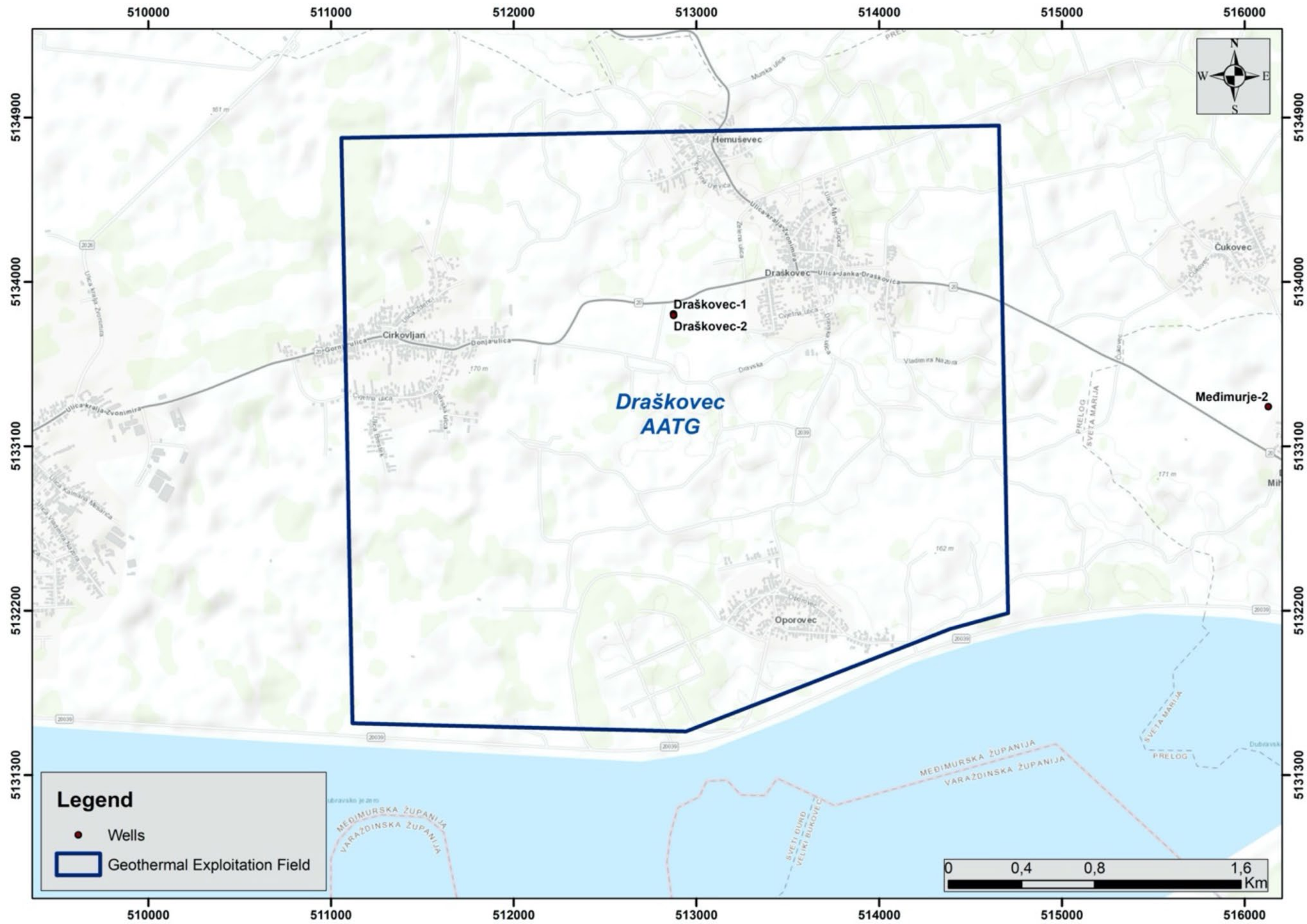


Fig. 22 Geothermal field Draškovec AATG

is used to heat the swimming pool and the premises of the Sports and Recreation Centre "Stjepan Radić" and the Faculty of Kinesiology (Energetika net 2020). The system has the ability to expand the capacity, taking into account the maximum flow rate of the well Mla-3 of 50.0 l/s and the injection capacity of the well Mla-2 of 50.0 l/s at an injection pressure of 10.0 bar. The system can be connected to another injection well Mla-1, whose injection capacity is 8.3 l/s at an injection pressure of 12.0 bar. The Blato technological system is not in operation and is intended for use in the planned sports and recreation zone. Four wells can be included in the system: KBNZ-1A and KBNZ-1B as production wells with flow rates of 5.0 and 65.0 l/s, respectively, KBNZ-3α and KBNZ-2A as injection wells with a maximum injection rate of 50.0 l/s (injection pressure 15.0 bar) and 35.0 l/s (injection pressure 25.0 bar), respectively (GPC Instrumentation process Ltd., 2018). The well Lučanka-1, at the Lučko site, is used for space heating of a private industrial facility. Since there is no injection well, the brine flows into a retention pond where it is cooled and afterward released into the local stream via channel.

Velika Ciglena geothermal field

The Velika Ciglena geothermal field with the first Croatian geothermal power plant is located in the Drava depression, near the town of Bjelovar (Fig. 26). In the 1970s and 1980s,

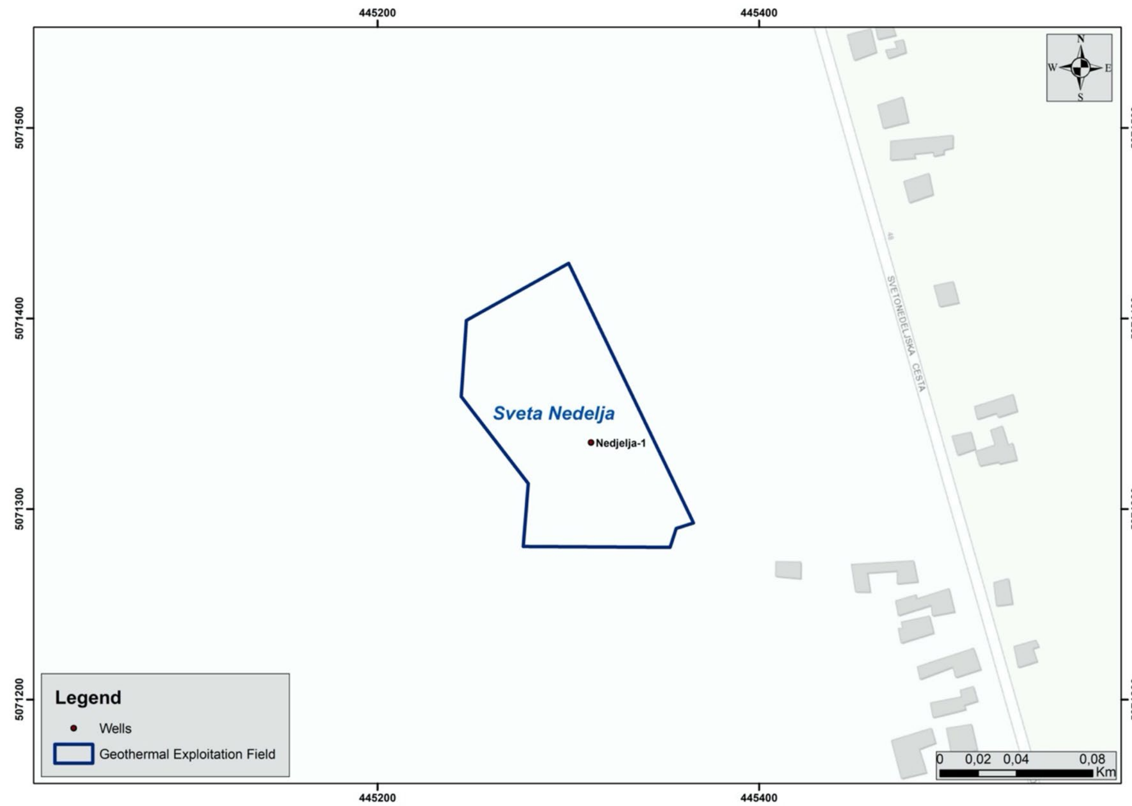


Fig. 23 Geothermal field Sveta Nedelja

the Drava depression was the subject of intensive work for oil and gas exploration. Data from gravimetric, magnetometric and seismic surveys as well as drilling data were collected. The first well in this field was the Velika Ciglena -1 well (VC -1). The Velika Ciglena -1 well was commissioned in 1990 and had the task of drilling pre-Neogene reservoirs and determining the existence of hydrocarbons. During the construction of the well, 5 DST tests were carried out. During the construction of the interval 2,545.0 to 2,607.0 m, dolomite breccias were drilled and total losses occurred during the drilling (2,585.0 m), while the tests (DST-4) showed poor permeability of the layer. When the influx of water occurred, a new DST test was carried out, which again did not give satisfactory results and it was concluded that the well had drilled the Tertiary basement. Losses during the construction of the well continued almost from a depth of 2,607.0 m to the bottom of the well at 4,790.0 m, and fragments of dolomite breccia belonging to the pre-Neogene basement were found throughout the interval. The highest temperature recorded on the thermometer was 170.0 °C. As the measuring instruments were not suitable for measuring such high temperatures, even higher temperatures were assumed. Subsequent well tests confirmed a temperature of 177.6 °C at a depth of 3,593.0 m. Analysis of the measurements showed a low reservoir permeability of 7.73×10^{-3} μm^2 do 13.03×10^{-3} μm^2 (INA-Industrija nafte d.d., 2007). After the drilling was completed and the results collected, it was decided to drill a new directional well to be used as a geothermal well. In the same year, another well was drilled–Velika Ciglena-1A, a deviated well, the wellhead of which is 10.0 m away from the Velika Ciglena-1 well. The final depth of the well is 2,956.0 m (Hv = 2,787.44 m).

Fig. 24 Geothermal field Bošnjaci-North

During the construction of the well, there were also total mud losses from 2,609.0 m to the final depth of the well of 2,956.0 m. The interval is part of the Tertiary reservoir and consists of dolomite breccias. Subsequent well tests of the reservoir and interference tests between wells Velika Ciglena-1 and -1A a permeability of about 400.0×10^{-3} μm^2. At the Velika Ciglena -1A well, the highest measured flow was 92.77 l/s, while at Velika Ciglena-1 a flow of 99.39 l/s was measured. Two more wells were drilled in the Velika Ciglena field–Patkovec-1 and Velika Ciglena-2, which confirmed the geothermal reservoir and were later completed as injection wells in the field. During further development of the field, additional tests were conducted, which confirmed a flow rate of 227.0 l/s and a well temperature of 166.0 °C, as well as a thermal output of 81.0 MW_t. Due to its reservoir parameters, the Velika Ciglena geothermal field was an ideal candidate for power generation (Rašković et al. 2013; Guzović et al. 2014). Based on the reservoir parameters, the wells VC -1 and VC -1a are used as production wells, while the wells PT -1 and VC -2 are injection wells. The gross installed power capacity of the Velika-1 geothermal power plant is 16.5 MW_e, but due to infrastructure constraints the nominal working capacity is 10.0 MW_e net (Geoen Ltd., 2017). The Velika-1 geothermal power plant was commissioned in March 2019 and produces electricity with an average availability of 85.92% (Croatian Energy Market Operator 2021).

Summary of Croatian geothermal exploitation fields

Table 8 presents summarised data for geothermal exploitation field which are currently under consessions. The geothermal gradient in exploitation sites varies from 0.046 up to 0.060 °C/m. Current power capacity in Croatia is at

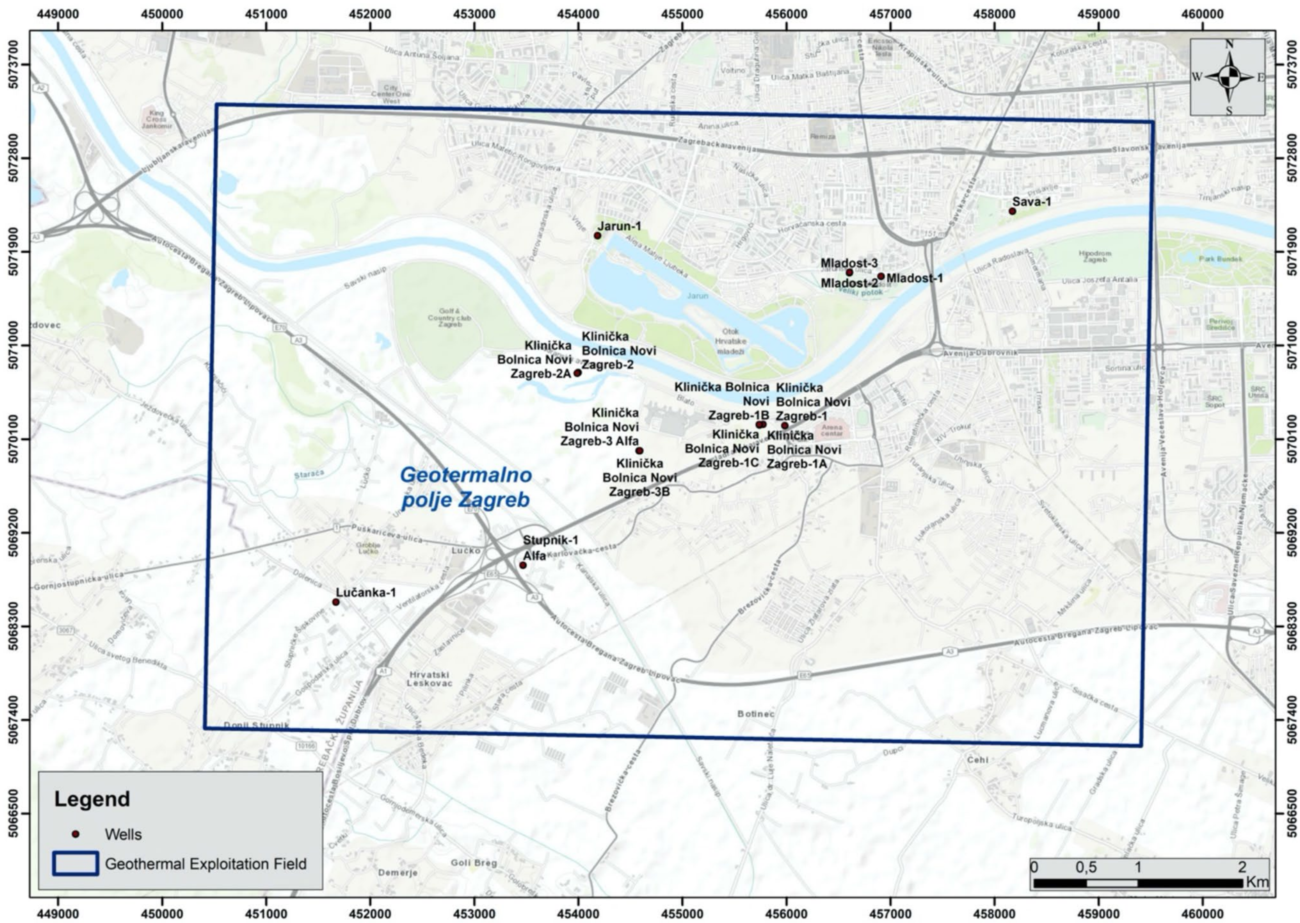


Fig. 25 Geothermal field Zagreb

16.5 MW_e, but more is expected with the development of Draškovec exploitation field as well as exploration sites like Slatina, Lunjkovec–Kutnjak, etc.

Conclusion

Current state of the art of geothermal reservoirs exploration and exploitation was presented for the Republic of Croatia. Described prominent geothermal sites are only a small fragment of the entire geothermal potential of the Pannonian Basin. Summarised data for geothermal exploration and exploitation fields are shown in Tables 5 and 8, respectively. Until now, as part of a broader screening process conducted by the lead author and Croatian Hydrocarbon Agency, drilling data, geophysical exploration data and well testing data from more than 150 well sites were initially collected and categorised or are in the process of research. 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 geothermal energy resource once hydrocarbon production is terminated. Such locations have very detailed geological data available, originating from geological exploration works, as well as

Table 7 Well status—geothermal field Zagreb (Ministarstvo gospodarstva i održivog razvoja, 2014)

	Well	Well depth (m)	Bottom temperature (°C)	Intervals (m)	Status (in 2014)
1	Mladost-1	1,057.0	59.0	911.0–1047.0	Monitoring
2	Mladost-2	911.7 (Hv = 829.9)	63.0	881.0–912.0	Injection
3	Mladost-3	1,362.2 (Hv = 990.8)	83.1	1,169.0–1,362.0	Production
4	KBNZ-1A	1,133.8	80.0	961.2–1,114.5	Injection
5	KBNZ-1B	1,374.0	80.0	1,217.0–1,374.0	Production
6	KBNZ-2	1,508.7	52.9	1,177.2–1,406.0	Monitoring
7	KBNZ-2A	1,267.0 (Hv = 1,190.2)	56.0	1,028.0–1,198.0	Injection
8	KBNZ-3	1,076.50	–	–	Abandoned
9	KBNZ-3a	981.0 (Hv = 825.1)	57.0	900.0–981.0	Injection
10	KBNZ-3B	1.378,7 (Hv = 1,000.2)	34.0	1,245.0–1,374.0	Monitoring
11	Lučanka-1	950.0	53.0	751.0–887.1	Production
12	Jarun-1	1,365.0	45.0	–	Monitoring
13	Sava-1	1,594.3	60.0	990.0–1,203.0	Monitoring
14	Stupnik-1	832.7 (Hv = 826.7)	46.0	–	Abandoned
15	Stupnik-1A	826.7	–	730.0–830.0	Monitoring

Table 8 Summarised data of geothermal exploitation fields in Croatia

Exploitation field	Average gradient (°C/m)	Flow (1P) (l/s)	Flow (2P) (l/s)	Thermal output (1P) (MW_t)	Thermal output (2P) (MW_t)	Power capacity (MW_e)
Ivanić	0.050	3.0	–	0.35	–	–
Bizovac	0.055	4.6	7.8	0.76	1,279.0	–
Draškovec	0.044	–	52.1	–	13.0	–
Sveta Nedjelja	0.056	25.0	–	–	–	–
Bošnjaci-North	0.060	10.0	–	1.4	–	–
Zagreb	0.050	6.2	77.1	1.3	15.7	–
Velika Ciglena	0.046	227.0	–	81.0	–	16.5

data obtained from production, injection, monitoring or exploration wells constructed during the oil and gas field exploitation period. Depending on the temperature from such bottom aquifers, geothermal brine could be used for direct heating purposes, or in some cases even for power generation. The advantage of using bottom aquifer brine is seen not only in good geological determination but also in already present well assets, which could be converted and used for geothermal brine production. Re-using of wells, where possible, also has economical benefits, since such a project would have lower investment costs. Bottom aquifer exploitation can have higher certainty of project completion due to lower geological uncertainty and good know-how derived from hydrocarbon exploration and exploitation works, already present at the location. So, this untapped geothermal potential from the oil and gas industry is the next phase for Croatian geothermal exploration. With this tremendous move forward in developing a geothermal data room available for future investors to analyse, an increase in geothermal energy share in the final energy consumption in the Republic of Croatia would be secured, as part of the green energy transition.

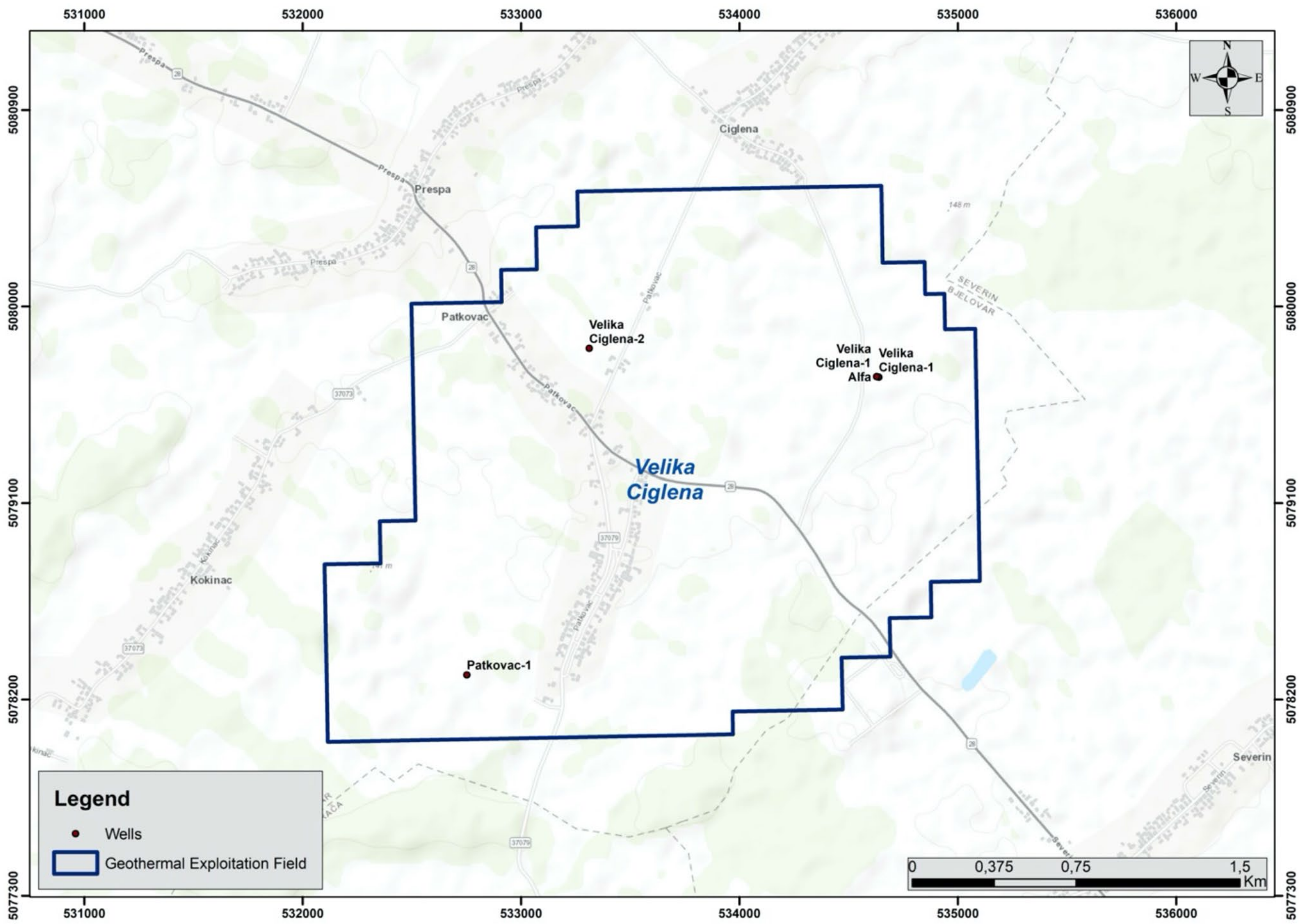


Fig. 26 Velika Ciglena geothermal field

References

AAT Geothermae Ltd (2017) Pilot project, available at. http://aatg.energy/pilot-project

AAT Geothermae Ltd (2016) Elaborat o rezervama geotermalne vode u istražnom prostoru Draškovec AATG. Zagreb, original documentation available in Croatian Hydrocarbon Agency

Borović S, Marković I (2015) Utilization and tourism valorisation of geohermal waters in Croatia. Renew Suistain Energy Rev 44:52–63

Cazin V, Jurilj Ž (2019) Eksploatacijsko polje geotermalne vode Zagreb i mogućnosti njezinog korištenja. Nafta i Plin 38(156):62–73

Croatian Energy Market Operator (2021) available at. https://www.hrote.hr/izvjestaji

Croatian Hydrocarbon Agency (2018) Dokumentacija za nadmetanja radi odabira najpovoljnijeg ponuditelja za istraživanje geotermalnih voda u istražnim prostorima „Slatina 1“, „Slatina 2“, „Slatina 3“ i „Slatina 4“ radi izdavanja dozvole za pridobivanje geotermalnih voda u energetske svrhe, available at. https://www.azu.hr/media/1597/dokumentacija-za-nadmetanje-slatina_0507_hq.pdf

Croatian Hydrocarbon Agency (2019a) Dokumentacija za nadmetanje u postupku nadmetanja radi odabira najpovoljnijeg ponuditelja za istraživanje geotermalnih voda u istražnom prostoru Virovitica-2, available at. https://www.azu.hr/media/1722/dokumentacija-za-nadmetanje_-virovitica-2__final.pdf

Croatian Hydrocarbon Agency (2019b) Dokumentacija za nadmetanje u postupku nadmetanja radi odabira najpovoljnijeg ponuditelja za istraživanje geotermalnih voda u istražnom prostoru Križevci, available at. https://www.azu.hr/media/1714/dokumentacija-za-nadmetanje_kri%C5%BEevci_hq.pdf

Croatian Hydrocarbon Agency (2019c) Dokumentacija za nadmetanje u postupku nadmetanja radi odabira najpovoljnijeg ponuditelja za istraživanje geotermalnih voda u istražnim prostorima “Babina Greda 1” I “Babina Greda 2” radi izdavanja dozvole za pridobivanje geotermalnih voda u energetske svrhe. Available at: https://www.azu.hr/media/1708/nacrt_dokumentacija-za-nadmetanje-babina-greda-1-2_hq_final.pdf. Accessed 15 May 2021

Croatian Hydrocarbon Agency (2020a) Dokumentacija za nadmetanje u postupku nadmetanja radi odabira najpovoljnijeg ponuditelja za pridobivanje geotermalnih voda u energetske srhe u istražnom porstoru "Korenovo", available at. https://www.azu.hr/media/1857/dokumentacija-za-nadmetanje_korenovo_final_clean.pdf

Croatian Hydrocarbon Agency (2020b) Bidding round documentation for granting a licence for the exploration of geothermal waters in the Ernestinovo exploration block, available at. https://www.azu.hr/media/1808/dokumentacija-za-nadmetanje_ernestinovo_eng.pdf

Croatian Hydrocarbon Agency (2020c) Bidding round documentation for granting a licence for the exploration of geothermal waters

in the Legrad-1 exploration block, available at. https://www.azu.hr/media/1809/dokumentacija-za-nadmetanje_legrad-1_eng.pdf
Croatian Hydrocarbon Agency (2020d) Bidding round documentation for granting a licence for the exploration of geothermal waters in the Lunjkovec-Kutnjak exploration block, available at. https://www.azu.hr/media/1810/dokumentacija-za-nadmetanje_lunjkovec-kutnjak-eng.pdf
Croatian Hydrocarbon Agency (2020e) Bidding round documentation for granting a licence for the exploration of geothermal waters in the Merhatovec exploration block, available at. https://www.azu.hr/media/1807/dokumentacija-za-nadmetanje_merhatovec.pdf
Cvetković M, Matoš B, Rukavina D, Kolenković Močilac I, Saftić B, Baketarić T, Paškov T (2019) Geoenergy potential of the Croatian part of Pannonian Basin: insights from the reconstruction of the pre-Neogen basement unconfirmity. J Map 15(2):651–661
DiPippo R (2004) Second law assessment of binary plants generating power from low-temperature geothermal fluids. Geothermics 33:565–586
Durn T, Krpan M (2016) Onshore Croatia: Hydrocarbon opportunities at the crossroads of Europe. GeoExPro - petroleum geoscience magazine, 16
Eko Plodovi, Ltd (2018) Elaborat zaštite okoliša u postupku ocjene o potrebi procjene utjecaja na okoliš eksploatacije geotermalne vode za energetske potrebe na budućem eksploatacijskom polju "Sveta Nedelja", available at. https://mingor.gov.hr/UserDocsImages/ARHIVA%20DOKUMENATA/ARHIVA%20---%20OPUO/elaborat_zastite_okolisa_861.pdf
Energetika net (2020) Energetika net available at: http://www.energetika-net.com/vijesti/obnovljivi-izvori-energije/veliki-potencijali-na-geotermalnoj-busotini-blizu-stupnika-31440
GPC Instrumentation process (2018) Elaborat o rezervama geotermalne vode eksploatacijskog polja "Geotermalno polje Zagreb". Zagreb, original documentation available at Croatian Hydrocarbon Agency
Geoen Ltd (2017) Elaborat o rezervama geotermalne vode eksploatacijskog polja Velika Ciglena. Zagreb, original documentation available at Croatian Hydrocarbon Agency
Guzović Z, Majcen B, Cvetković S (2012) Possibilities of electricity generation in the Republic of Croatia from medium-temperature geothermal sources. Appl Energy 98:404–414
Guzović Z, Rašković P, Blatarić Z (2014) The comparison of a basic and a dual-pressure ORC (Organic Rankine Cycle): Geothermal Power Plant Velika Ciglena case study. Energy 76:175–186
Horváth F, Musitz B, Balázs A, Végh A (2015) Evolution of the Pannonian basin and its geothermal resources. Geothermics 53:328–352
INA-industrija nafte, Naftaplin (1993a) Elaborat o rezervama geotermalne vode - geotermalno polje Bizovac. Zagreb, original documentation available at Croatian Hydrocarbon Agency
INA-industrija nafte (1993b) Elaborat o rezervama geotermalne vode zagrebačkog geotermalnog ležišta. Zagreb, original documentation available at Croatian Hydrocarbon Agency
INA-Industrija nafte d.d (2005) Elaborat o rezervama geotermalne vode eksploatacijskog polja GT Ivanić, zagreb. Zagreb, original documentation available at Croatian Hydrocarbon Agency
INA-Industrija nafte d.d (2007) Elaborat o rezervama geotermalne vode u istražnom prostoru "Drava" geotermalnog polja Velika Ciglena. Zagreb, original documentation available at Croatian Hydrocarbon Agency
INA-Industrija nafte d.d (2016) Elaborat o rezervama geotermalne vode eksploatacijskog polja GT Ivanić. Zagreb, original documentation available at Croatian Hydrocarbon Agency
INA-Industrija nafte d.d (2021) Elaborat o rezervama geotermalne vode eksploatacijskog polja Bizovac, stanje 31.12.2020. Zagreb, original documentation available at Croatian Hydrocarbon Agency
Jelić K, Kevrić I, Krasić O (1995) Temperatura i toplinski tok u tlu Hrvatske. First Croatian Geological Congress - Proceedings, 1:245–249
Kurevija T, Vulin D (2011) High enthalpy geothermal potential of deep gas fields in Central Drava Basin, Croatia. Water Resour Manag 25(12):3041–3052
Lenkey L, Dövényi P, Horvath F, Cloetingh S (2002) Geothermics of the Pannonian basin and its bearing on the neotectonics. Stephan Mueller Spec Publ Ser 3:29–40
Lund JW, Toth AN (2020) Direct utilization of geothermal energy 2020 worldwide review. Geothermics 90:101915
Lučić D, Krizmanić K, Prelogović E, Britić V, Mesić I, Tadej J (2001) The Neogene evolution and hydrocarbon potential of the Pannonian Basin in Croatia. Mar Pet Geol 18(1):133–147
Macenić M, Kurevija T, Medved I (2020) Novel geothermal gradient map of the Croatian part of the Pannonian Basin System based on data interpretation from 154 deep exploration wells. Renew Sustain Energy Rev 110069:132
Macenić M, Kurevija T, Strpić K (2018) Systematic review of research and utilization of shallow geothermal energy in Croatia. Rud Geol Naft Zb 43(5):1–11
Malvić T, Cvetković M (2013) Lithostratigraphic units in the Drava Depression (Croatian and Hungarian parts) - a correlation. Nafta 64(1):27–33
Malvić T, Pimenta Dinis M, Velić J, Sremac J, Ivšinović J, Bošnjak M, Pedrosa E, Sousa H (2020) Geological risk calculation through probability of success (PoS), applied to radioactive waste disposal in deep wells: a conceptual study in the pre-Neogen basement in the northern Croatia. Processes 8(7):755
Malvić T, Velić J (2011) Neogene tectonics in Croatian part of the Pannonian Basin and reflectance in hydrocarbon accumulations. Rijeka, Intech 352:215–238
Marković T, Borović S, Larva O (2015) Geochemical characteristics of thermal waters of Hrvatsko Zagorje. Geol Croat 68:67–77
Ministarstvo gospodarstva i održivog razvoja (2014) Available at. https://mingor.gov.hr/UserDocsImages/ARHIVA%20DOKUMENATA/ARHIVA%20---%20PUO/2013/11082014_rjesenje_ministarstva_od_25_srpnja_2014_godine.pdf
Official Gazzette (2018) Act on the exploration and production of hydrocarbons. The Croatian Parliament, Republic of Croatia
Official Gazzette (2019) Act amending the act on the exploration and production of hydrocarbons. The Croatian Parliament, Republic of Croatia
Official Gazzette (2021) Act amending the act on the exploration and production of hydrocarbons. The Croatian Parliament, Republic of Croatia
Prelogović E, Saftić B, Kuk V, Velić J, Dragaš M, Lučić D (1998) Tectonic activity in the Croatian part of the Pannonian basin. Tectonophysics 297:283–293
Rašković P, Guzović Z, Cvetković S (2013) Performance analysis of electricity generation by the medium temperature geothermal resources: Velika Ciglena case study. Energy 54:11–31
Royden L, Horváth F, Rumpler J (1983) Evolution of the Pannonian Basin System: 1. Tectonics. Tecton 2(1):63–90. https://doi.org/10.1029/tc002i001p00063
Ruris (2018) Elaborat o rezervama geotermalne vode u istražnom prostoru "Bošnjaci-sjever". Zagreb, original documentation available at Croatian Hydrocarbon Agency
Saftić B, Velić J, Sztanó O, Juhász G, Ivković Ž (2003) Tertiary subsurface facies, source rocks and hydrocarbon reservoirs in the SW part of the Pannonian Basin (Northern Croatia and South-Western Hungary). Geol Croat 56(1):101–122
Sebe K, Kovačić M, Magyar I, Krizmanić K, Špelić M, Bigunac D, Sztano O (2020) Correlation of upper Miocene-Pliocene Lake Pannon deposits across the Drava Basin, Croatia and Hungary. Geol Croat 73(3):177–195
Velić J, Malvić T, Cvetković M, Vrbanac B (2012) Reservoir geology, hydrocarbon reserves and production in the Croatian part of the Pannonian Basin System. Geol Croat 65(1):91–101

Šumanovac F, Orešković J, Grad M, ALP 2002 Working Group (2009) Crustal structure at the contact of the Dinarides and Pannonian basin based on 2-D seismic and gravity interpretation of the Alp07 profile in the ALP 2002 experiment. Geophys J Int 179(1):615–633

Živković S, Kolbah S, Škrlec M, Tumara D (2019) Geothermal energy use, country update for Croatia. Den Haag

Publisher's Note Springer Nature remains neutral with regard to jurisdictional claims in published maps and institutional affiliations.

Tuschl, M., Kurevija, T. Defining Heat in Place for the Discovered Geothermal Brine Reservoirs in the Croatian Part of Pannonian Basin. Water 2023, 15 (6), 1237. https://doi.org/10.3390/w15061237.

water

MDPI

Article

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

check for updates

Citation: Tuschl, M.; Kurevija, T. Defining Heat in Place for the Discovered Geothermal Brine Reservoirs in the Croatian Part of Pannonian Basin. *Water* **2023**, *15*, 1237. https://doi.org/10.3390/w15061237

Academic Editors: Cara Beal and Oz Sahin

Received: 25 January 2023
Revised: 2 March 2023
Accepted: 10 March 2023
Published: 22 March 2023

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].

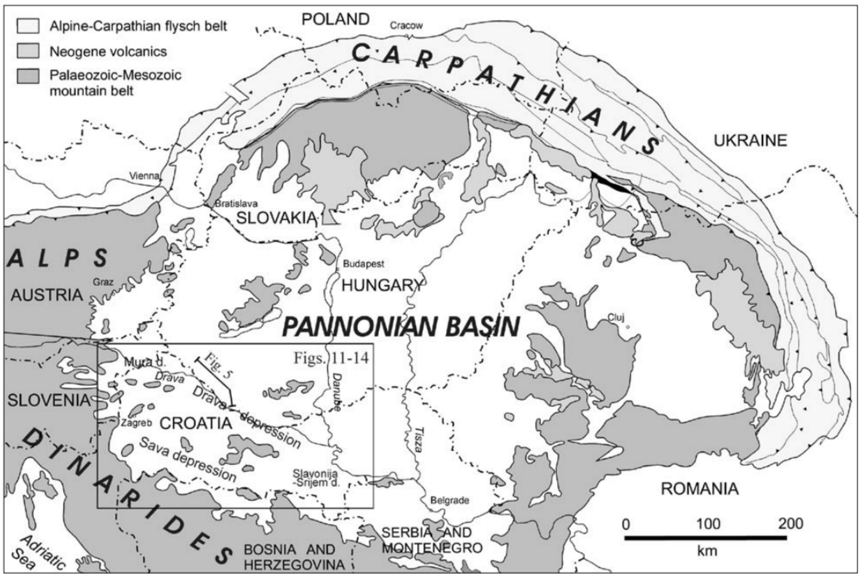


Figure 1. Location of the Croatian part of the Pannonian Basin System within the Pannonian Basin [53].

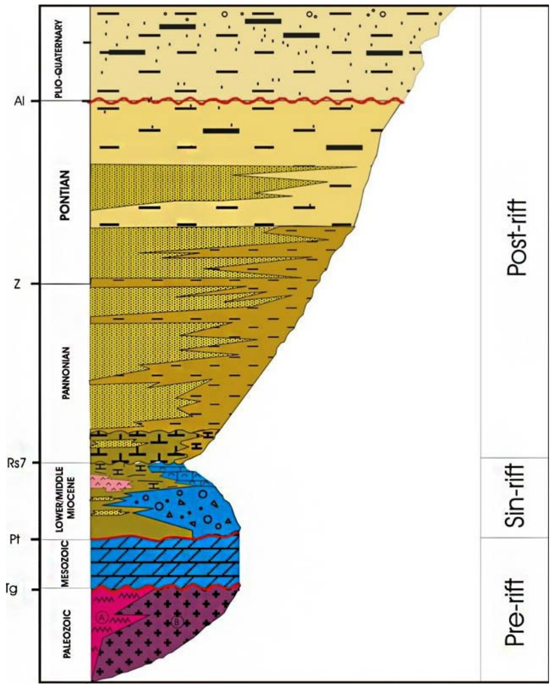


Figure 2. Schematic geological column of the Pannonian basin [53,61].

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.

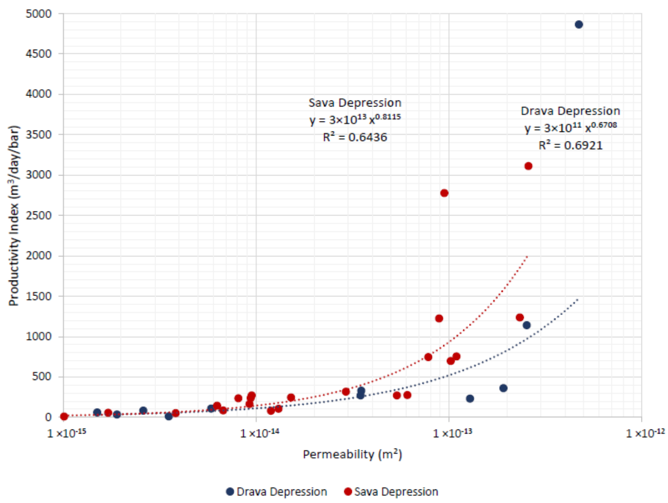


Figure 3. Productivity index vs. permeability data correlation—post-rift phase.

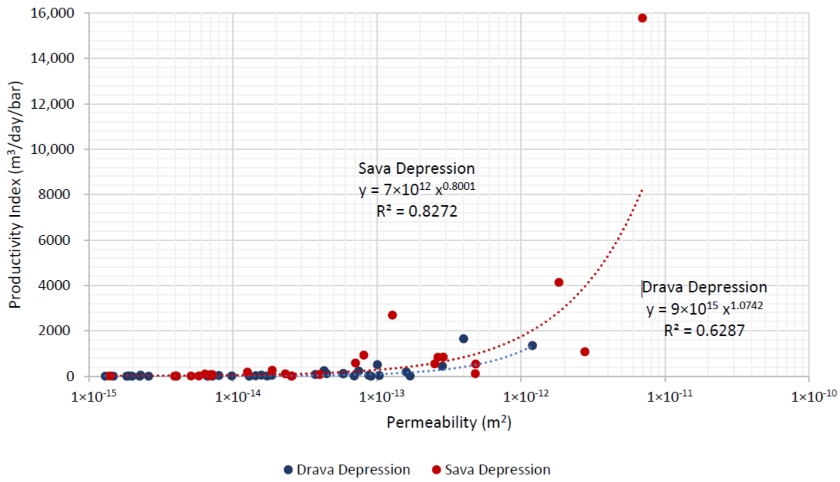


Figure 4. Productivity index vs. permeability data correlation—syn-rift phase.

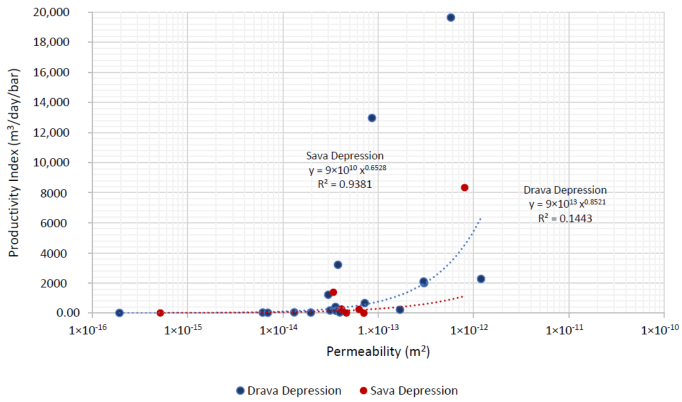


Figure 5. PI vs. Permeability data correlation—pre-rift phase.

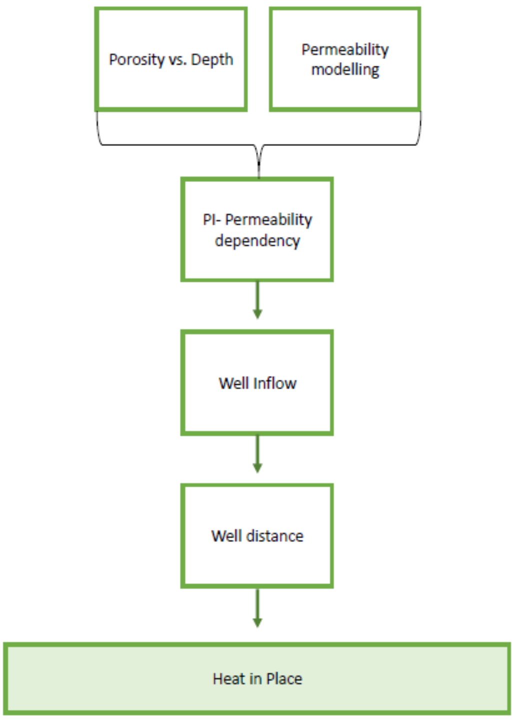


Figure 6. Calculation of heat-in-place flow chart.

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

$$\rho_S = -0.792e^{-0.725H} + 2.72 \quad (8)$$

while Drava Depression is expressed by the following formula:

$$\rho_D = -0.747e^{-0.809H} + 2.72 \quad (9)$$

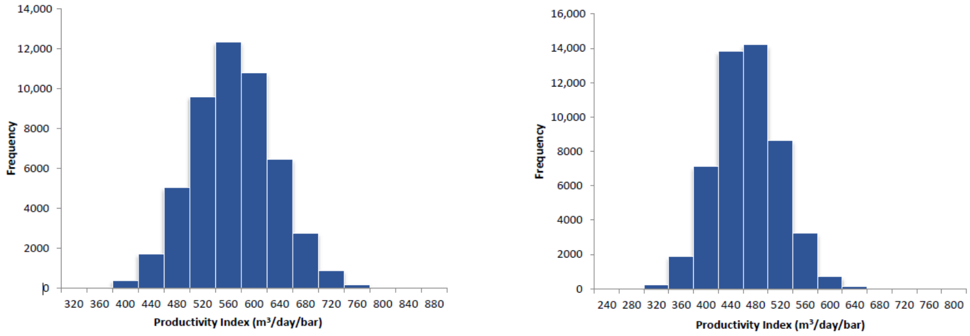
For specific rock heat in Sava depression, this expression is used:

$$c_S = 0.602e^{-1.177H} + 0.898 \quad (10)$$

For Drava depression,

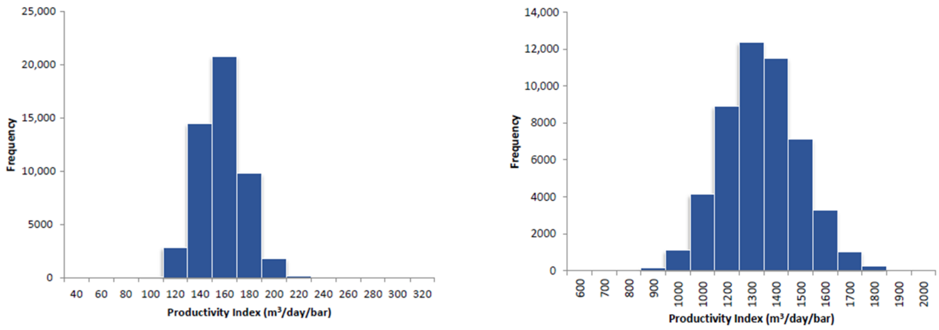
$$c_D = 0.557e^{-1.460H} + 0.908 \quad (11)$$

where H is the depth of reservoir in metres.



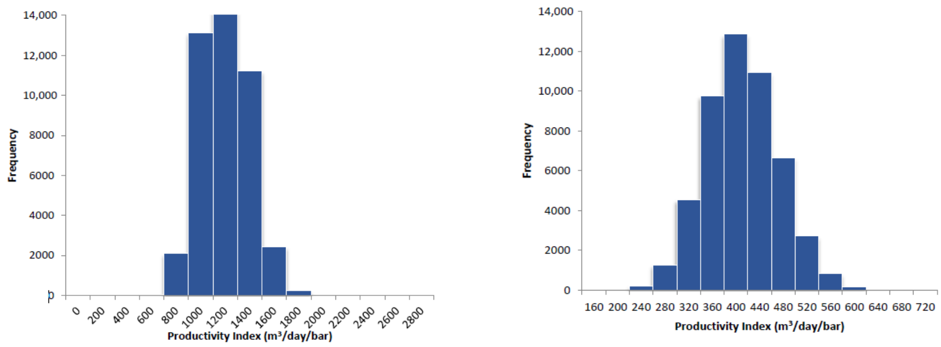
(**a**) (**b**)

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.

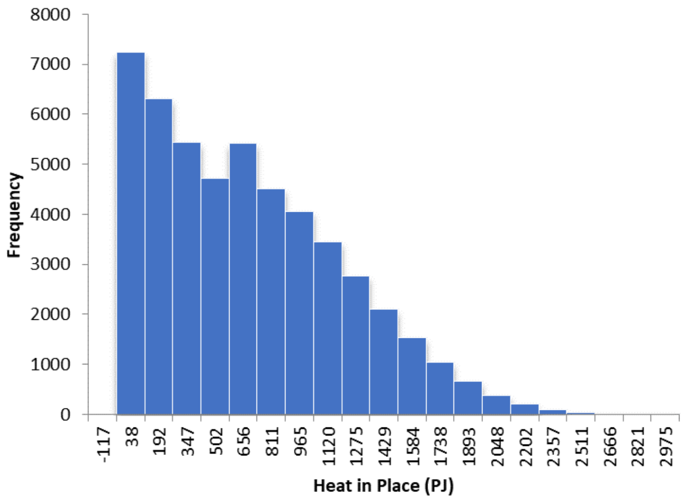


Figure 10. Heat-in-place probability distribution for well doublets—post-rift phase.

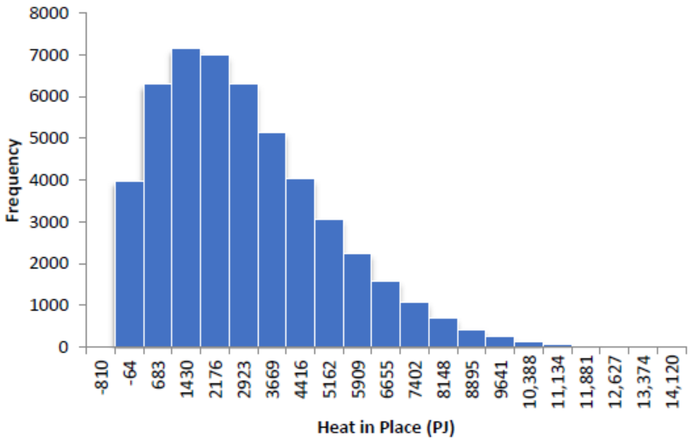


Figure 11. Heat-in-place probability distribution for well doublets—syn-rift phase.

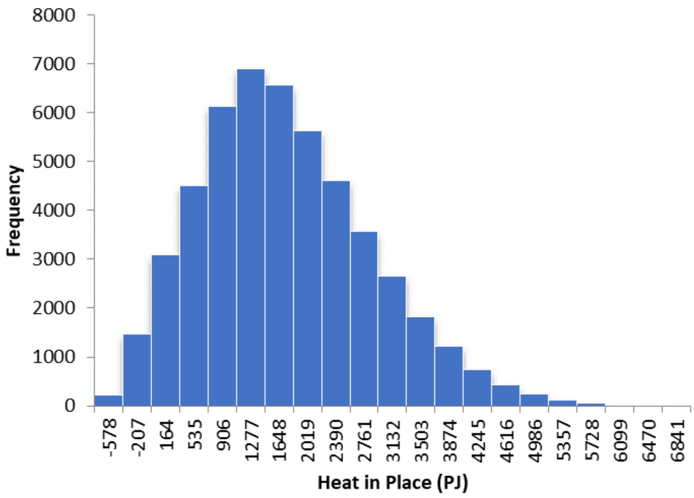


Figure 12. Heat-in-place probability distribution for well doublets—pre-rift phase.

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

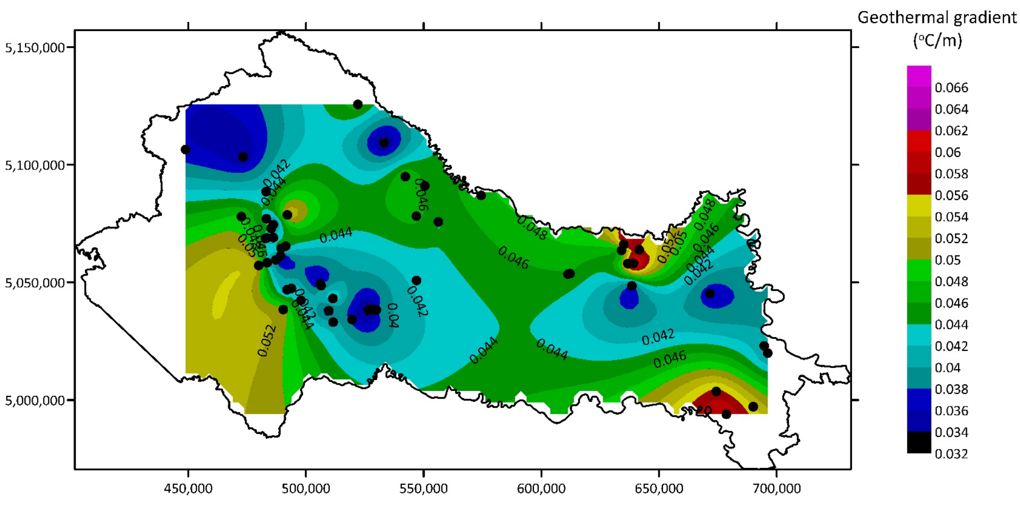


Figure 13. Geothermal gradient map for post-rift phase.

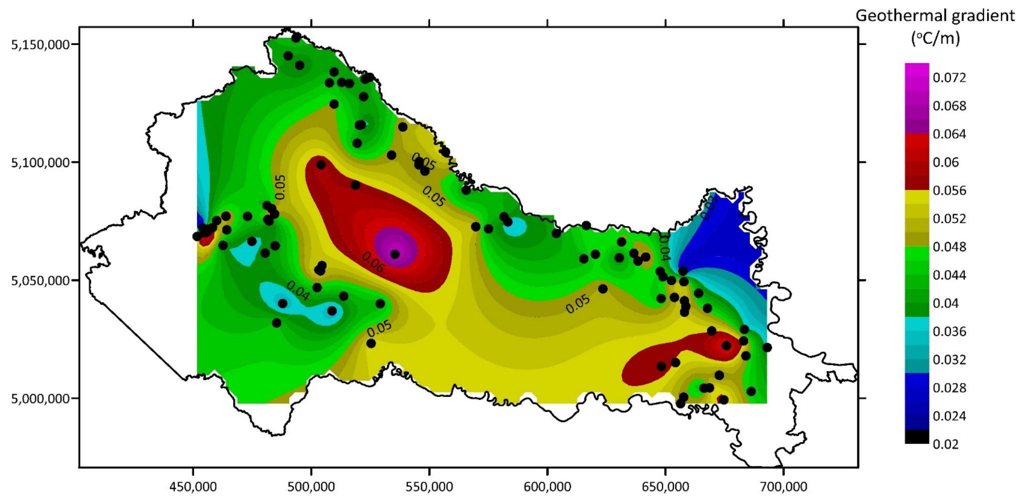


Figure 14. Geothermal gradient map for syn-rift phase.

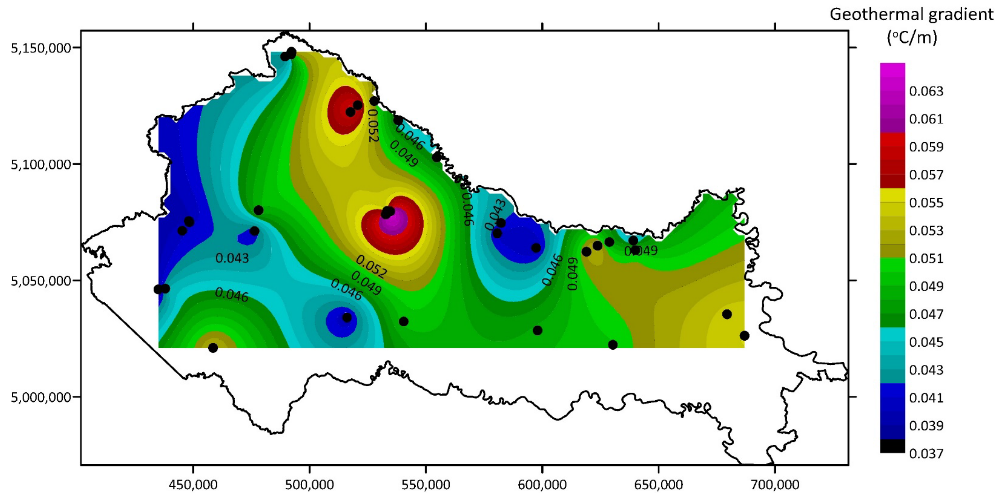


Figure 15. Geothermal gradient map for pre-rift phase.

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.

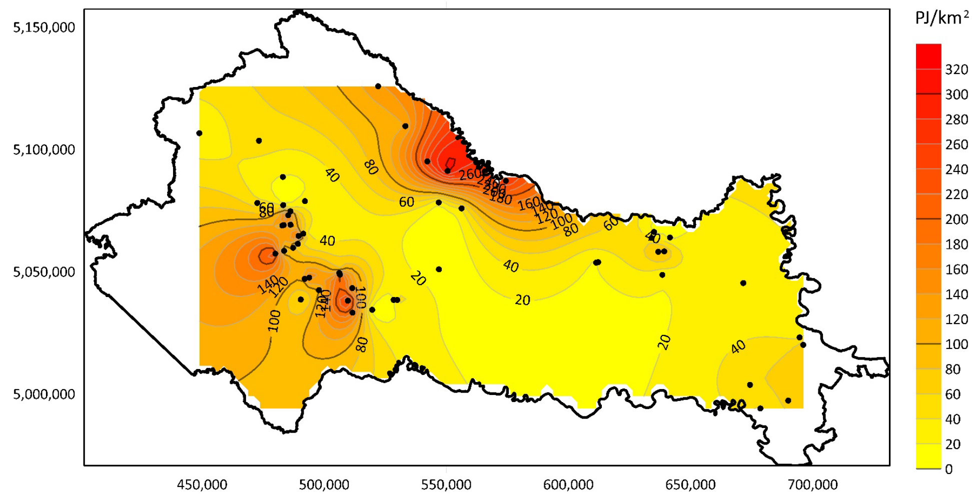


Figure 16. Mean heat-in-place areal distribution—post-rift phase.

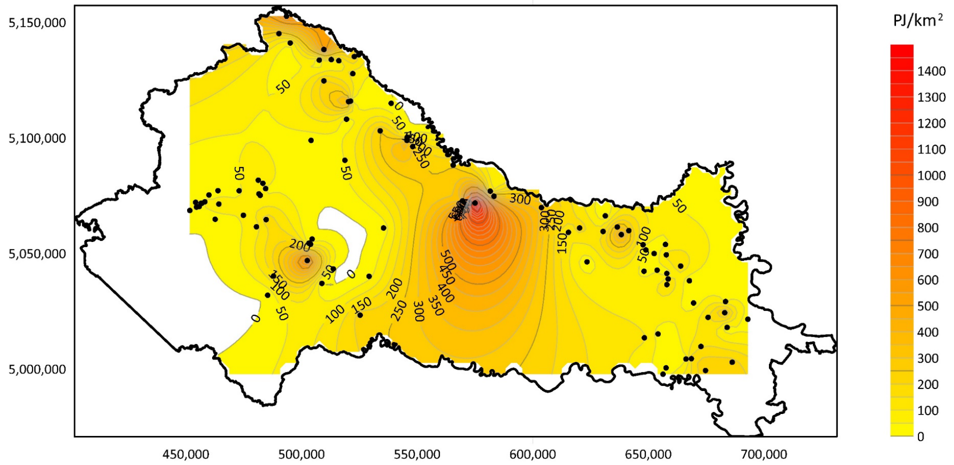


Figure 17. Mean heat-in-place areal distribution—syn-rift phase.

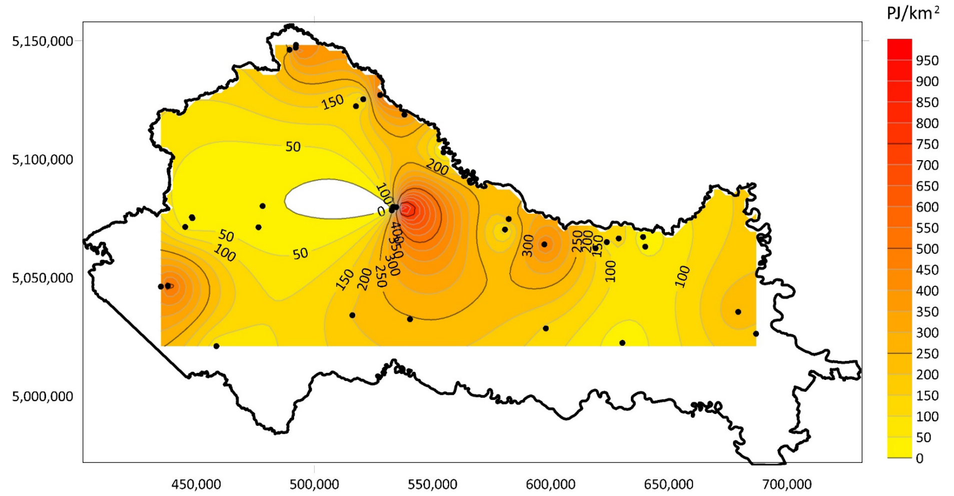


Figure 18. Mean heat-in-place areal distribution—pre-rift phase.

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

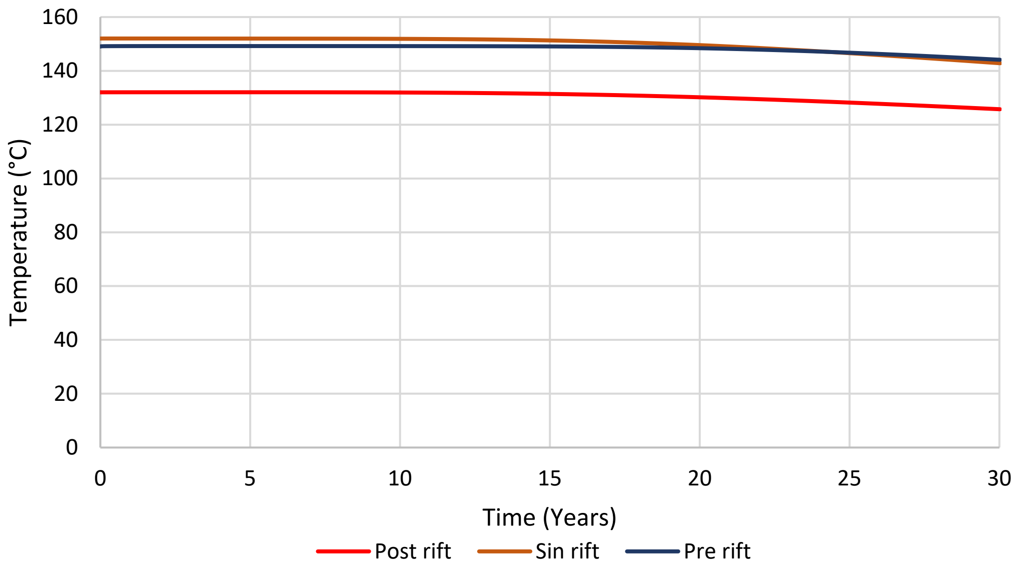


Figure 19. Temperature change around a doublet in the simulation programme.

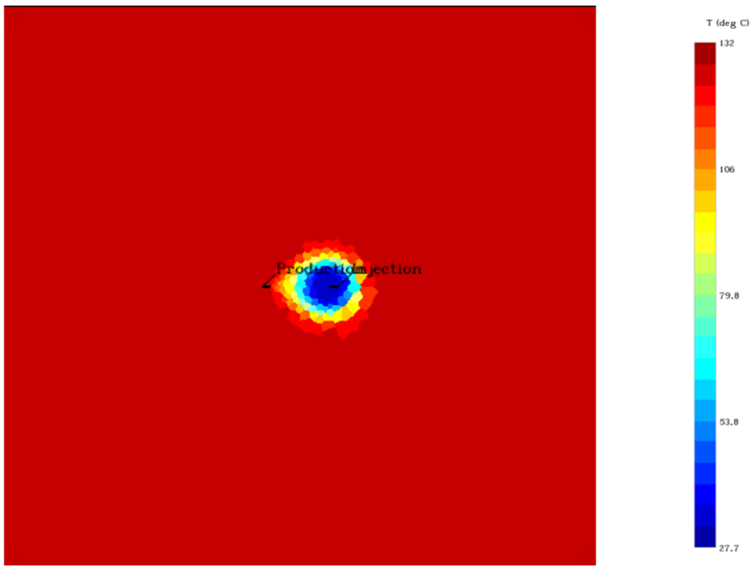


Figure 20. Model simulation of well doublet temperature distribution after 30 years of production—post-rift phase.

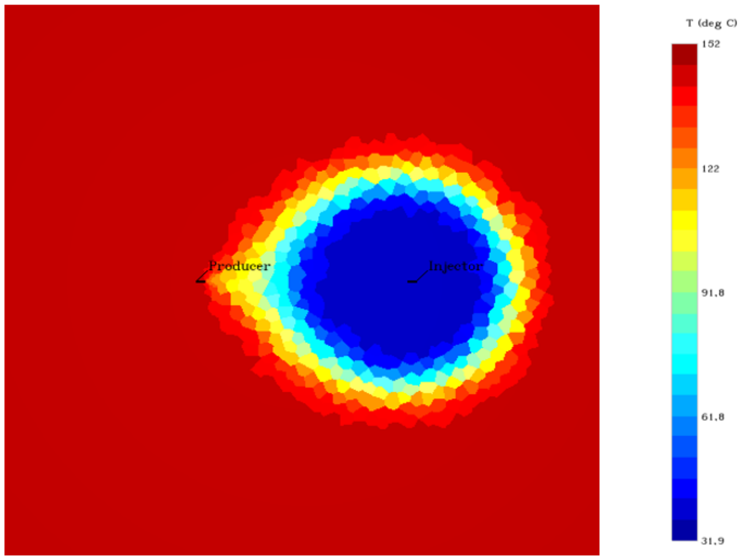


Figure 21. Model simulation of well doublet temperature distribution after 30 years of production—syn-rift phase.

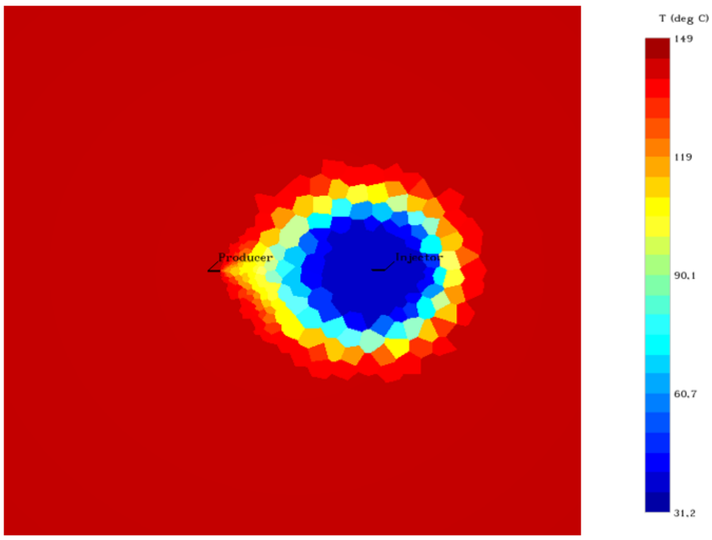


Figure 22. Model simulation of well doublet temperature distribution after 30 years of production—pre-rift phase.

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.

Author Contributions: Conceptualization: M.T.; Methodology: M.T. & T.K.; Simulations M.T.; Validation: T.K., Writing original draft and review: M.T. & T.K. Supervision: T.K. Investigation: M.T. All authors have read and agreed to the published version of the manuscript.

Funding: This research was partially funded by Development fund of Faculty of mining, geology and petroleum engineering, Zagreb, Croatia.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: All data used in the analysis are the property of the Republic of Croatia and were obtained from the database of the Croatian Hydrocarbon Agency and may be used for scientific research purposes.

Conflicts of Interest: The authors declare no conflict of interest.

References

1. European Commission. Green Plan. 2019. Available online: https://sustainabledevelopment.un.org/post2015/transformingourworld (accessed on 15 August 2022).
2. European Commision. Recovery and Resiliance Facility. 2020. Available online: https://ec.europa.eu/info/business-economy-euro/recovery-coronavirus/recovery-and-resilience-facility_en#the-recovery-and-resilience-facility (accessed on 15 August 2022).
3. Dekanić, I.; Kolundžić, S.; Daria, K. Stoljeće Nafte. In *Veza Između Nafte, Novca i Noći Noja je Promijenila Svijet*, 2nd ed.; Naklada Zadro: Zagreb, Croatia, 2003.
4. Tuschl, M.; Kurevija, T.; Krpan, M.; Macenić, M. Overview of the current activities related to deep geothermal energy utilisation in the Republic of Croatia. *Clean Technol. Environ. Policy* **2022**, *24*, 3003–3031. [CrossRef]

5. Jelić, K.; Ćubrić, S.; Pavičić, H.; Bošnjak, R. Geothermal Energy Potential and Utilization in the Republic of. World Geothermal Congress. In Proceedings of the World Geothermal Congress 2000, Tohoku, Japan, 28 May–10 June 2000; pp. 237–246.
6. Jelić, K.; Kevrić, I.; Krasić, O. Temperatura i toplinski tok u tlu Hrvatske. In Proceedings of the 1. Croatian Geological Congress, Zagreb, Croatia, 18–21 October 1995; Croatian Geological Society. pp. 245–249.
7. Jelić, K. Thermodynamic Characteristics of Sedimentary Complex of SW Part of Pannonian Basin (In Croatian: Termodinamičke Osobine Sedimentnog Kompleksa Jugozapadnog Dijela Panonskog Bazena). Ph.D. Thesis, University of Zagreb, Zagreb, Croatia, 1979.
8. Macenić, M.; Kurevija, T.; Medved, I. Novel Geothermal Gradient map of the Croatian Part of the Pannonian Basin System Based on Data Interpretation from 154 Deep Exploration wells. *Renew. Sustain. Energy Rev.* **2020**, *132*, 110069. [CrossRef]
9. Brobst, D.A.; Pratt, W.P. (Eds.) *United States Mineral Resources*; Geological Survey: Washington, DC, USA, 1973.
10. Franco, A.; Donatini, F. Methods for the estimation of the energy stored in geothermal reservoirs. *J. Physics: Conf. Ser.* **2017**, *796*, 012025. [CrossRef]
11. UNFC. United Nations Framework Classification for Fossil Energy and Mineral Reserves and Resources 2009. Economic Commission for Europe, ECE Energy Series No. 39, United Nations, New York and Geneva. 2010. Available online: https://unece.org/DAM/energy/se/pdfs/UNFC/unfc2009/UNFC2009_ES39_e.pdf (accessed on 1 September 2022).
12. Rybach, L. Classification of Geothermal Resources by Potential. *Geotherm. Energy Sci.* **2015**, *3*, 13–17. [CrossRef]
13. Muffler, L.J.P. Assesment of Geothermal Resources of the United States. *Geol. Surv. Circ.* **1978**, *790*, 163.
14. Muffler, P.; Cataldi, R. Methods for regional assessment of geothermal resources. *Geothermics* **1978**, *7*, 53–89. [CrossRef]
15. Limberger, J.; Boxem, T.; Pluymaekers, M.; Bruhn, D.; Manzella, A.; Calcagno, P.; Beekman, F.; Cloetingh, S.; van Wees, J.-D. Geothermal Energy in Deep Aquifers: A Global Assessment of the Resource Base for Direct Heat Utilization. *Renew. Sustain. Energy Rev.* **2018**, *82*, 961–975. [CrossRef]
16. Kramers, L.; van Wees, J.-D.; Pluymaekers, M.; Kronimus, A.; Boxem, T. Direct Heat Resource Assessment and Subsurface Information Systems for Geothermal Aquifers; the Dutch Perspective. *Neth. J. Geosci.* **2012**, *91*, 637–649. [CrossRef]
17. van Wees, J.-D.; Kronimus, A.; van Putten, M.P.D.; Pluymaekers, M.; Mijnlieff, H.; van Hooff, P.; Obdam, A.; Kramers, L. Geothermal Aquifer Performance Assessment for Direct Heat Production—Methodology and Application to Rotliegend Aquifers. *Neth. J. Geosci.* **2012**, *91*, 651–665. [CrossRef]
18. Garg, S.K.; Jim, C. Appropriate Use of USGS Volumetric Heat in Place Method and Monte Carlo Calculations. In Proceedings of the Thirty-Fourth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, USA, 1–3 February 2010; Available online: https://pangea.stanford.edu/ERE/pdf/IGAstandard/SGW/2010/garg.pdf (accessed on 1 August 2022).
19. Garg, S.K.; Combs, J. A reformulation of USGS Volumetric "Heat in Place" Resource Estimation Method. *Geothermics* **2015**, *55*, 150–158. [CrossRef]
20. Takahashi, S.; Yoshida, S. Improvement of Calculating Formulas for Volumetric Resource Assessment. *Geothermics* **2016**, *64*, 187–195. [CrossRef]
21. Shinya, T.; Yoshida, S. A Desktop Review of Calculation Equations for Geothermal Volumetric Assessment. In Proceedings of the 43rd Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, USA, 12–14 February 2018; pp. 1–18.
22. Williams, C.F.; Reed, M.J.; Robert, H.M. A Review of Methods Applied by the U.S. Geological Survey in the Assessment of Identified Geothermal Resources. In *Open-File Report 2008–1296*; U.S. Geological Survey: Reston, VA, USA, 2008; 30p.
23. Kalos, M.H.; Paula, A. Whitlock. In *Monte Carlo Methods*, 2nd ed.; Wiley-Blackwell: Hoboken, NJ, USA, 2008.
24. Franco, A.; Vaccaro, M. Sustainable Sizing of Geothermal Power Plants: Appropriate Potential Assessment Methods. *Sustainability* **2020**, *12*, 3844. [CrossRef]
25. González-García, H.; Francke, H.; Sass, I.; Huenges, E. Production Forecast and Estimation of the Recovery Factor of the Los Humeros Geothermal Field, Mexico. *Geotherm. Energy* **2021**, *9*, 13. [CrossRef]
26. Kahrobaei, S.; Fonseca, R.M.; Willems, C.J.L.; Wilschut, F.; van Wees, J.D. Regional Scale Geothermal Field Development Optimization under Geological Uncertainties. In Proceedings of the European Geothermal Conference 2019, Den Haag, The Netherlands, 11–14 June 2019.
27. Nádor, A.; Sebess-Zilahi, L.; Rotár-Szalkai, Á.; Gulyás, Á.; Markovic, T. New Methods of Geothermal Potential Assessment in the Pannonian Basin. *Neth. J. Geosci.* **2019**, *98*, e10. [CrossRef]
28. Shah, M.; Vaidya, D.; Sircar, A. Using Monte Carlo Simulation to Estimate Geothermal Resource in Dholera Geothermal Field, Gujarat, India. *Multiscale Multidiscip. Model. Exp. Des.* **2018**, *1*, 83–95. [CrossRef]
29. Aravena, D.; Muñoz, M.; Morata, D.; Lahsen, A.; Parada, M.; Dobson, P. Assessment of High Enthalpy Geothermal Resources and Promising Areas of Chile. *Geothermics* **2016**, *59*, 1–13. [CrossRef]
30. Athens, N.D.; Caers, J.K. A Monte Carlo-Based Framework for Assessing the Value of Information and Development Risk in Geothermal Exploration. *Appl. Energy* **2019**, *256*, 113932. [CrossRef]
31. Iglesias, E.R.; Torres, R.J. Low- to Medium-Temperature Geothermal Reserves in Mexico: A First Assessment. *Geothermics* **2003**, *32*, 711–719. [CrossRef]
32. Miranda, M.M.; Raymond, J.; Dezayes, C. Uncertainty and Risk Evaluation of Deep Geothermal Energy Source for Heat Production and Electricity Generation in Remote Northern Regions. *Energies* **2020**, *13*, 4221. [CrossRef]
33. Agemar, T.; Weber, J.; Moeck, I.S. Assessment and Public Reporting of Geothermal Resources in Germany: Review and Outlook. *Energies* **2018**, *11*, 332. [CrossRef]

34. Eyerer, S.; Schifflechner, C.; Hofbauer, S.; Bauer, W.; Wieland, C.; Spliethoff, H. Combined Heat and Power from Hydrothermal Geothermal Resources in Germany: An Assessment of the Potential. *Renew. Sustain. Energy Rev.* **2020**, *120*, 109661. [CrossRef]
35. Zhang, L.; Gao, C.; Ji, B.; Zhang, R.; Niu, J. A Simplified Assessment Method for Estimating Recoverable Geothermal Resources. *Geothermics* **2019**, *79*, 145–151. [CrossRef]
36. Gringarten, A.C.; Sauty, J.P. A Theoretical Study of Heat Extraction from Aquifers with Uniform Regional Flow. *J. Geophys. Res. Atmos.* **1975**, *80*, 4956–4962. [CrossRef]
37. Gringarten, A.C. Reservoir Lifetime and Heat Recovery Factor in Geothermal Aquifers Used for Urban Heating. *Pure Appl. Geophys. PAGEOPH* **1978**, *117*, 297–308. [CrossRef]
38. Augustine, C. Analysis of Sedimentary Geothermal Systems Using an Analytical Reservoir Model. *Trans. Geotherm. Resour. Counc.* **2014**, *38*, 641–647.
39. Li, T.; Shiozawa, S.; McClure, M.W. Thermal Breakthrough Calculations to Optimize Design of a Multiple-Stage Enhanced Geothermal System. *Geothermics* **2016**, *64*, 455–465. [CrossRef]
40. Chen, S.-Y.; Hsieh, B.-Z.; Hsu, K.-C.; Chang, Y.-F.; Liu, J.-W.; Fan, K.-C.; Chiang, L.-W.; Han, Y.-L. Well spacing of the doublet at the Huangtsuishan geothermal site, Taiwan. *Geothermics* **2020**, *89*, 101968. [CrossRef]
41. Kamila, Z.; Kaya, E.; Zarrouk, S.J. Reinjection in Geothermal Fields: An Updated Worldwide Review 2020. *Geothermics* **2020**, *89*, 101970. [CrossRef]
42. Patterson, J.R.; Cardiff, M.; Feigl, K.L. Optimizing Geothermal Production in Fractured Rock Reservoirs under Uncertainty. *Geothermics* **2020**, *88*, 101906. [CrossRef]
43. Willems, C.; Nick, H.; Goense, T.; Bruhn, D. The Impact of Reduction of Doublet Well Spacing on the Net Present Value and the Life Time of Fluvial Hot Sedimentary Aquifer Doublets. *Geothermics* **2017**, *68*, 54–66. [CrossRef]
44. Royden, L.; Horváth, F.; Rumpler, J. Evolution of the Pannonian Basin System: 1. Tectonics. *Tectonics* **1983**, *2*, 63–90. [CrossRef]
45. Velić, J.; Malvić, T.; Cvetković, M.; Vrbanac, B. Reservoir Geology, Hydrocarbon Reserves and Production in the Croatian part of the Pannonian Basin. *Geol. Croat.* **2012**, *65*, 91–101. [CrossRef]
46. Ferenc, H.; Royden, L. Mechanism for Formation of the Intra-Carpathian Basins: A Review. *Earth Evol. Sci.* **1981**, *3*, 307–316.
47. Lučić, D.; Saftić, B.; Krizmanić, K.; Prelogović, E.; Britvić, V.; Mesić, I.; Tadej, J. The Neogene Evolution and Hydrocarbon Potential of the Pannonian Basin in Croatia. *Mar. Pet. Geol.* **2001**, *18*, 133–147. [CrossRef]
48. Pavelić, D. Tectonostratigraphic Model for the North Croatian and North Bosnian Sector of the Miocene Pannonian Basin System. *Basin Res.* **2001**, *13*, 359–376. [CrossRef]
49. Tari, G.C. *Alpine Tectonics of the Pannonian Basin*; Rice University: Houston, TX, USA, 1994.
50. Tari, V.; Pamić, J. Geodynamic Evolution of the Northern Dinarides and the Southern Part of the Pannonian Basin. *Tectonophysics* **1998**, *297*, 269–281. [CrossRef]
51. Velić, J. *Geologija Ležišta Nafte i Plina (Geology of Oil and Gas Reservoirs)*; University of Zagreb: Zagreb, Croatia, 2007.
52. Saftić, B.; Malvić, T. *Dubinska Kartiranje (Depth Mapping)*; University of Zagreb: Zagreb, Croatia, 2008.
53. Saftić, B.; Velić, J.; Sztano, O.; Juhasz, G.; Ivković, Ž.; Nafte, D.I.I. Tertiary Subsurface Facies, Source Rocks and Hydrocarbon Reservoirs in the SW Part of the Pannonian Basin (Northern Croatia and South-Western Hungary). *Geol. Croat.* **2003**, *56*, 101–122. [CrossRef]
54. Horváth, F.; Tari, G. IBS Pannonian Basin Project: A Review of the Main Results and Their Bearings on Hydrocarbon Exploration. *Geol. Soc. London, Spéc. Publ.* **1999**, *156*, 195–213. [CrossRef]
55. Ćorić, S.; Pavelić, D.; Rögl, F.; Mandić, O.; Vrabac, S.; Avanić, R.; Jerković, L.; Vranjković, A. Revised Middle Miocene Datum for Initial Marine Flooding of North Croatian Basins (Pannonian Basin System, Central Paratethys). *Geol. Croat.* **2009**, *62*, 31–43. [CrossRef]
56. Malvić, T.; Naftaplin, Z.I.; Velić, J.; Peh, Z.; Survey, Z.C.G. Qualitative–Quantitative Analyses of the Influence of Depth and Lithological Composition on Lower Pontian Sandstone Porosity in the Central Part of Bjelovar Sag (Croatia). *Geol. Croat.* **2005**, *58*, 73–85. [CrossRef]
57. Royden, L. Late Cenozoic Tectonics of the Pannonian Basin System. In *AAPG Memoir 45*; Royden, H.L., Horváth, F., Eds.; American Association of Petroleum Geologists: Tulsa, OK, USA, 1988; pp. 27–48.
58. Velić, J.; Weisser, M.; Saftić, B.; Vrbanac, B.; Ivković, Ž. Petroleum-Geological Characteristics and Exploration Level of the Three Neogene Depositional Megacycles in the Croatian Part of the Pannonian Basin. *NAFTA* **2002**, *53*, 239–249.
59. Vrbanac, B.; Velić, J.; Malvić, T. Sedimentation of Deep-Water Turbidites in the SW Part of the Pannonian Basin. *Geol. Carpathica* **2010**, *61*, 55–69. [CrossRef]
60. Malvić, T.; Velic, J. Neogene Tectonics in Croatian Part of the Pannonian Basin and Reflectance in Hydrocarbon Accumulations. In *New Frontiers in Tectonic Research—At the Midst of Plate Convergence*; Schattner, U., Ed.; InTech eBooks: Rijeka, Croatia, 2011. [CrossRef]
61. Durn, T.; Krpan, M. *Onshore Croatia: Hydrocarbon Opportunities at the Crossroads of Europe*; Geoexpo: Heggedal, Norway, 2019; Available online: https://www.geoexpro.com/articles/2019/02/onshore-croatia-hydrocarbon-opportunities-at-the-crossroads-of-europe (accessed on 1 August 2022).

62. Förster, A.; Merriam, D.F.; Davis, J.C. Spatial Analysis of Temperature (BHT/DST) Data and Consequences for Heat-Flow Determination in Sedimentary Basins. *Int. J. Earth Sci.* **1997**, *86*, 252–261. [CrossRef]
63. Gray, D.A.; Majorowicz, J.; Unsworth, M. Investigation of the Geothermal State of Sedimentary Basins Using Oil Industry Thermal Data: Case Study from Northern Alberta Exhibiting the Need to Systematically Remove Biased Data. *J. Geophys. Eng.* **2012**, *9*, 534–548. [CrossRef]

Tuschl, M., Kurevija, T. Revitalization Modelling of a Mature Oil Field with Bottom-Type Aquifer into Geothermal Resource—Reservoir Engineering and Techno-Economic Challenges. Energies 2023, 16 (18), 6599, https://doi.org/10.3390/en16186599

energies

Article

Revitalization Modelling of a Mature Oil Field with Bottom-Type Aquifer into Geothermal Resource—Reservoir Engineering and Techno-Economic Challenges

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

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

Abstract: The possibilities of using geothermal energy are slowly expanding to all areas of energy consumption, so the assessment of geothermal potential has become the backbone of energy policies in countries that have the potential. Countries and companies that have experience in the oil and gas industry are increasingly exploring the possibilities of first using the acquired knowledge, and then using the existing oil and gas infrastructure for the use of geothermal energy. For this reason, it is necessary to analyse the possibilities of using the existing infrastructure with all its limitations to maximise the energy potential of geothermal energy. The existing oil infrastructure, especially the wells, is in many cases not suitable for the production of brine and it is necessary to analyse the maximum impact of each well for the production of geothermal energy, with particular attention to the equipment installed in the well and the thickness of the geothermal reservoir in the oil and gas fields that would be suitable for the production of brine.

Keywords: geothermal energy; brine flow; mature oil field; abandoned oil well; economics

Citation: Tuschl, M.; Kurevija, T. Revitalization Modelling of a Mature Oil Field with Bottom-Type Aquifer into Geothermal Resource—Reservoir Engineering and Techno-Economic Challenges. *Energies* **2023**, *16*, 6599. https://doi.org/10.3390/en16186599

Academic Editor: Fangming Jiang

Received: 9 August 2023
Revised: 8 September 2023
Accepted: 11 September 2023
Published: 13 September 2023

1. Introduction

Geothermal energy has its advantages over other renewable energy sources as it is available 24/7, but for almost 10 years the total capacity of installed geothermal energy has been growing slowly. According to IRENA [1], a total of 14,877 MW of geothermal energy was installed worldwide in 2022, with an average increase of 3.31% in installed capacity since 2013. In Europe, 1634 MW were installed in 2022, with an average growth of 1.23% compared to 2013, although there was no new installed capacity in 2022 compared to 2021. Although geothermal energy has a local character and depends on the geological conditions for its extraction, the growth share of geothermal energy is extremely slow.

Apart from the geological predetermination of a particular area, one of the reasons for the slow development of geothermal energy is its high price. The cost of drilling a geothermal well accounts for 40–50% of the total capital investment in a geothermal project [2]. Augustine et al., 2006 [3], note that the cost of drilling geothermal wells is even higher than the cost of drilling oil or gas wells at the same depth, as in the oil and gas industry, the costs of geothermal exploration drilling are financed by the investor's equity. As the discovery risk at this stage is high and the use of equity is required to finance the drilling, geothermal energy is not attractive to investors. There is great learning potential in the construction of geothermal wells, especially with regard to the typical formations that are geothermal targets. However, when the specifics of geothermal well equipment are taken into account, they have a greater wellbore stability, but at the same time, this means a higher capital investment [4]. In order to increase the use of geothermal energy, especially with a view to reducing costs, countries that have already produced oil and gas in the past are examining their geothermal energy potential on the basis of abandoned oil and gas wells [5]. Oil fields have the potential for low to medium geothermal energy resources and have a wealth of data that should be used to reuse the fields and improve the technology for extracting geothermal energy from them [6]. The knowledge gained from the characterisation of the reservoirs, but also the political regulations in the petroleum industry, can help to expand the use of geothermal energy [7]. Appropriate solutions are already being applied, both in terms of regulatory possibilities and technical issues in the conversion of oil and gas fields to geothermal energy production, and in the use of the data provided by oil and gas activities for geothermal reservoir engineering [8–10].

In Croatia, the oil industry has a long tradition dating back to 1950, when the first oil and gas explorations took place. Along with the oil and gas discoveries, geothermal potential was also discovered, but not exploited in the energy sector. After more than 60 years of continuous production in Croatia, the depletion of oil and gas reservoirs is reaching its peak and many fields are about to be shut down. In the future, it will be necessary to invest significant funds for decommissioning, while, on the other hand, there is the potential for renewable energy in the form of deep and hot aquifers in old oil and gas reservoirs. To implement the Green Deal guidelines for the successful transition from fossil fuels to renewable energy, the use of aquifers from depleted oil and gas fields is of best practise in this direction, especially in terms of using the findings from deep oil and gas fields for use as renewable energy sources.

2. Materials and Methods

Geothermal energy can be used in various ways, from direct application in district heating, greenhouse heating, industrial processing, etc., to the generation of electricity, depending on the temperature and flow of the geothermal brine [11–14].

The conversion of oil fields into geothermal energy is the interest of many authors, as is the methodology for finding the best scenarios for extracting geothermal energy from aquifers and the methodology for selecting the best fields for this purpose [15–22]. Retrofitting oil wells is an idea that is gaining popularity as a possibility for using wells with deep heat exchangers [22,23]. Davis and Michaelides [24] analysed the potential of oil wells equipped with double-pipe heat exchangers and the use of secondary fluid as the working fluid. In this way, the net power produced can exceed 3 MW for temperatures at the bottom of the well of 450 K. Gharibi et al. [25] evaluates the feasibility of obtaining geothermal energy from an abandoned oil well that has been retrofitted with a U-tube heat exchanger and concludes that the obtained thermal energy can be used for direct application, and even for the production of electricity in certain circumstances. An example of using oil wells to generate geothermal energy was also presented by Wang et al. [26], through downhole power generation using thermoelectric generation technology.

In addition to the data available from oil and gas production, the use of existing wells lowers the cost of the future exploitation of geothermal wells. The use of abandoned oil and gas wells for geothermal energy also presents its own challenges, primarily relating to the selection of suitable wells, the availability of data and, above all, the integrity of the wells [27]. Among other challenges, according to Liu, 2018 [28], oil fields as geothermal resources are in the range of 65 to 150 °C, which belongs to the medium to low temperature category according to the classifications of many authors [29], and the method of exploitation should be adapted to the given conditions.

To classify geothermal energy, it is not enough to determine only the temperature, but it is necessary to determine its working capacity, i.e., the possibility of producing electricity or thermal energy [30]. According to Rybach, 2015 [31], renewable energy resources can be divided into five categories: theoretical, technical, economic, sustainable and development potential, which decrease in size and thus also maintain their financial framework.

The theoretical potential of geothermal water can be determined using Heat in Place, which describes the energy contained in the solid phase and the energy contained in the pores or water [32–34]. In order to calculate the heat contained in rock and the heat contained in water separately, the following expression is used:

$$H_i = H_r + H_w = (\Phi\, \rho_w\, c_w)\,(V_i)\,(T_i - T_0) + (1 - \Phi)(\rho_r\, c_r)\,(V_i)(T_i - T_0) \quad (1)$$

where H_i is the total volumetric heat of the rock and water (J), while H_r and H_w are the total volumetric heat contained in the rock and water, respectively (J); ϕ is the reservoir porosity, while c is the heat capacity (kJ/m^3/°C), the index r refers to the rock and the index w refers to the water. V_i is the volume of the rock and water (m^3), Ti is the initial temperature of the reservoir (°C) and T_0 is the initial temperature of the water (°C).

2.1. Organic Rankine Cycle

In terms of oil field temperature, the geothermal potential ranges from the low to the medium category [28]; energy from an oil field geothermal aquifer can be generated using an Organic Rankine Cycle (ORC). ORC power plants work on the principle of the Rankine cycle but use organic substances as the working medium (typical working fluids are isobutane, isopentane, R-134a and ammonia) instead of water. In the ORC, the heat coming from the geothermal aquifer heats the working fluid, whose steam then drives the turbine, whose rotary motion is transferred to the generator, which converts the kinetic energy into electricity. The working fluid is cooled in the condensers and returned to the circuit in the form of a liquid phase, and the process continues. When using ORC technology, special attention must be paid to the selection of the working fluid, the temperature and pressure of the condenser, the cooling medium and the choice of expander technology [35] in order to obtain optimal plant efficiency [36,37]. ORC power plants are particularly useful in situations where the heat sources are not strong enough to operate a classical steam power plant using water as the working medium, as they use low- and medium-temperature sources (<90–150 °C) [38] and are suitable for use with low and medium geothermal energy potential. The maximum theoretical output of the ORC, without taking into account heat transfer losses and the internal consumption of the power plant, is calculated using the potential maximum useful work corresponding to the change in the availability of the brine and the dead state under ambient or sink conditions [39]:

$$P_{ex} = q_g \times (\Delta h - T_0 \times \Delta s)\ |T_g, p_g;\ T_0,\ p_0 \quad (2)$$

Change in enthalpy:

$$\Delta h = h - h_0 = c_{pg} \times (T - T_0) \quad (3)$$

Change in entropy:

$$\Delta s = s - s_0 = c_{pg} \times \ln\left(\frac{T}{T_0}\right) \quad (4)$$

For constant pressure:

$$s = \int_{T_0}^{T} \frac{c_{pg}}{T} dT - R \ln \frac{p}{p_0} + s_0 \quad (5)$$

$$P_{ex} = q_g \times c_{pg}\left[\Delta T - T_0 \times \ln\left(1 + \frac{\Delta T}{T_0}\right)\right] \quad (6)$$

$$P_{ex} = q_g \times c_{pg}\left[\Delta T - T_0\left(\frac{\Delta T}{T_0} - \frac{1}{2}\frac{\Delta T^2}{T_0^2}\right)\right] \quad (7)$$

Final equation for the power output:

$$P_{ex} = q_g \times C_{pg} \frac{\Delta T^2}{2T_{g\ out}} \tag{8}$$

where P_{ex} is maximum theoretical power, q_g is the mass fluid flow, c_{pg} is the specific heat of the geothermal fluid, T_0 presents site conditions and $T_{g\ out}$ is the outlet temperature from the binary power plant heat exchanger.

The same relation could be defined through the First and Second Laws of thermodynamics:

$$P_{ex} = q_g \times c_{pg} \left[\Delta T - T_0 \times \ln\left(\frac{T_{g\ in}}{T_{g\ out}} \right) \times \eta_{util} \right] \tag{9}$$

The Second Law efficiency (η_{util}) for a given process is the ratio between the real work and the reversible work for a fictitious reversible process. For the Rankine cycle, the efficiency can be expressed as a function of the operating conditions of the cycle as well as the conditions of the sink and the brine temperatures:

$$\eta_{util} = \frac{\Delta T \ \times \eta_{cycle}}{\Delta T - T_0 \times \ln \frac{T_{g\ in}}{T_o}} \tag{10}$$

The thermodynamic efficiency of the binary power plant (η_{cycle}), or the efficiency described by the First Law of Thermodynamics, is the ratio between the net power developed by the cycle (P_{ex}) and the total available thermal energy from the geothermal source (Q_{tot}) at the surface [38]:

$$\eta_{cycle} = \frac{P_{ex}}{Q_{tot}} = \frac{q_g \ \times \frac{c_{pg} \times \Delta T^2}{2 \times Tgout}}{q_g \times c_{pg} \times \Delta T} = \frac{\Delta T}{2 \times T_{g\ out}} \tag{11}$$

2.2. Well Completion

The function of the well is to provide a connection between the surface and the reservoir in order to pump or inject fluid. The effectiveness of this connection affects the production characteristics of the reservoir, the total production achieved and the economics. Well completion is considered the most important operation during the life of the well. It includes almost all operations between the development of the well and the commissioning of the well [40]. The method of completion depends on and influences the production and future maintenance operations simultaneously. In general, the technology used in drilling petroleum wells and geothermal wells is very similar, with the choice of casing used in the drilling and the subsequent completion of the geothermal wells depending on the temperature, depth, the properties of the geothermal brine and the production characteristics that the well must achieve [41]. When drilling wells, casing is placed in the wellbore, considering the design and purpose of the well. The production interval can be completed in two basic ways—as an open hole and a cased hole [42]. Open holes are most commonly drilled in carbonate (consolidated) reservoirs. In this completion method, the casing is laid to the top of the production interval and cemented before the production zone is drilled through. Then, the open part of the well is drilled. A cased well means that the entire reservoir interval is cased and then perforated. The typical completion of oil wells in Croatia involves cased wells with a perforated production interval, where the outer diameter of the production casing is between 5 and 5 1/2″. The typical completion of oil wells in Croatia poses the greatest challenge to the use of the wells for geothermal energy. Geothermal wells are typically completed in such a way that the size of the wells in the production casing is between 13 3/8″, 9 5/8″ and 7″, while the diameters in the open hole are between 9 5/8″, 7″ and 5 1/2″ [4,41]. Due to the high temperatures, the casing is exposed to greater stress and must be cemented along its entire length [43].

2.3. Economic Evaluation

Financial decisions on long-term investments are some of the most complex decisions. An investment in long-term, real projects means an investment in fixed, tangible assets of a company. Therefore, investments in long-term projects are considered as investments in fixed assets that require the use of current assets. Geothermal projects represent a large capital burden, and reducing costs in the form of investment in the construction of new wells is an important contribution to reducing the initial investment [44,45]. The most common method for estimating the time value of capital is the net present value. Net present value is calculated by summing the future cash inflows, reduced to today's costs, over the life of the project.

$$\mathrm{NPV} = \sum\nolimits_{\mathrm{t}=1}^{\mathrm{t}} \frac{\mathrm{CF}}{(1+\mathrm{WACC})^{\mathrm{t}}} \tag{12}$$

where CF is the net cash inflows and outflows during the project period (t) and WACC is the weighted average cost of capital.

The weighted average cost of capital (WACC) represents the ratio between the assets the company is willing to invest, and the share of debt and business risk [46]. The WACC is used to estimate the cost of capital and thus the return that an investor receives for his investment. The capital asset pricing model (CAPM model) [47] estimates the weighted average cost of the capital. It introduces a risk-free interest rate as a variable representing the minimum return an investment can receive and combines it with the industry beta coefficient and the market return. The model CAMP was introduced by Sharp in 1964 [48] and is the basic method for estimating the cost of capital despite its shortcomings [49,50].

$$\mathrm{WACC} = [(\ \mathrm{W_E} \times \mathrm{r_e}\ ) + (\mathrm{W_D} \times \mathrm{r_d})] \times (1 - \mathrm{t_c}) \tag{13}$$

where $\mathrm{W_E}$ is the weighted value of equity, $\mathrm{r_e}$ is the cost of equity, $\mathrm{W_D}$ is the weighted value of debt, $\mathrm{r_d}$ is the cost of debt and $\mathrm{t_c}$ is corporate tax.

$$r_{e=}\ r_{f+}\beta_L \times \left(r_m - r_f\right) \tag{14}$$

where $\mathrm{r_e}$ is cost of equity, $\mathrm{r_f}$ is the risk-free rate, $\mathrm{r_m}$ is the expected return and β_{L} is the levered beta for equity.

2.4. Selection of Mature Oil Fields for Geothermal Production

In Croatia, oil and gas are produced from 54 fields. Of these, 42 are oil fields that are in the secondary phase of exploitation and where waterflooding is used to increase oil production [51]. This also means that the aquifers of these oil fields are approximately at the initial pressure level. If the temperature parameters are favourable for the extraction of geothermal water and there is the possibility of sufficient water inflow, these aquifers can be converted into geothermal fields and the existing infrastructure can be used for the production of renewable energy sources. This study analyses an oil field and the possibility of converting the oil field aquifer into a geothermal aquifer with existing oil production from shallower, oil-saturated reservoirs.

In order to examine the possibilities of repurposing oil fields, the Beničanci oil field was analysed. The field is located in the northern part of Slavonia in the Drava Depression, one of the four depressions in the Croatian part of the Pannonian Basin [52,53]. The analysed oil field was discovered in 1969 and production began in 1972 with 17 wells, and a total of 90 wells were drilled by the end of the 1970s. The well network is designed so that the wells are about 500 m apart. In the initial phase, oil production took place under the influence of the elastic energy regime, as there was no information about the influence of the aquifer. Currently, in the analysed oil field, 25 wells are producing oil, together with 10 injection wells, while the rest of the wells are shut-in or used as monitoring wells.

The structure of the oil reservoir is an elongated anticline (brachyanticline) extending from east to west, about 8 km long and 1.3 km wide. The following sequences of stratigraphic deposits were drilled—Mesozoic, Neogene and Quaternary (Figure 1). The oil reservoir mainly belongs to Badenian dolomite–limestone breccia of the Miocene age. The basic tectonic element of the field is a fault of reverse character, extending from the northwest to the southeast, and three zones of normal faulting have been identified in the western, central and eastern parts of the structure. It is considered that the oil reservoir, and consequently the geothermal reservoir, i.e., the aquifer of the oil field, constitutes a single hydrodynamic unit with a unique oil–water contact at −1955 m, and it is considered that the fault is not an obstacle to fluid flow (Figure 2) [54].

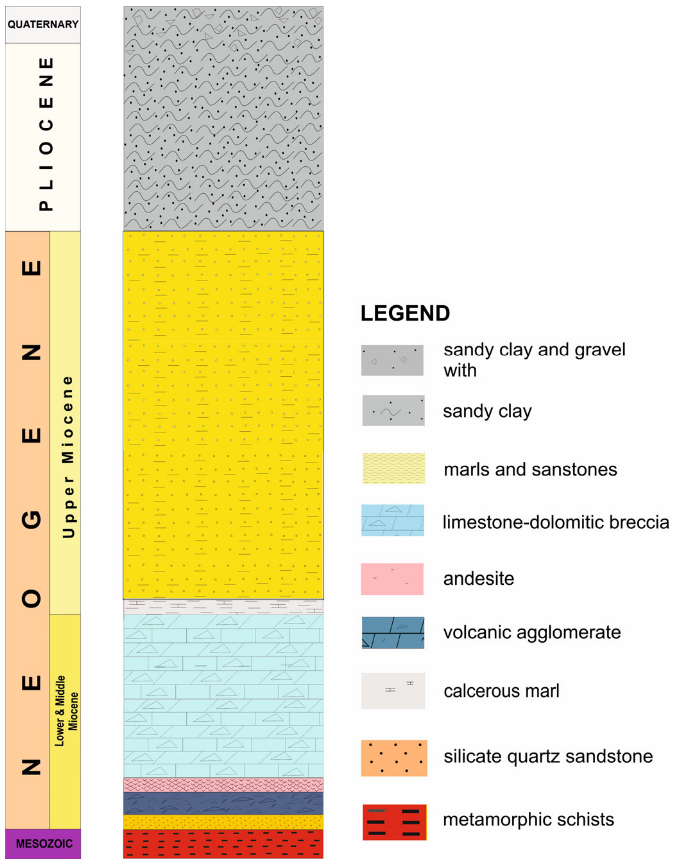


Figure 1. Schematic lithostratigraphic column of Beničanci oil field.

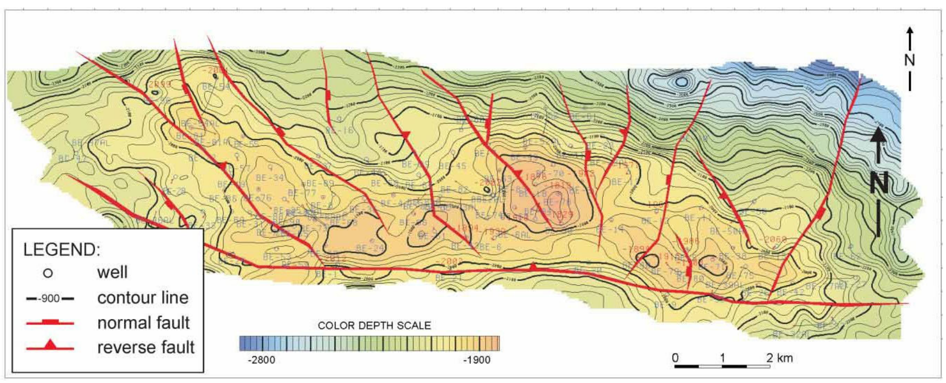


Figure 2. Structural map of main reservoir—Beničanci field [55,56].

The average porosity is 10% but varies from 4.6% to 14.5% due to the fracture system in the deposit. The initial reservoir pressure was 191 bar, and the initial reservoir temperature was 123.3 °C at the depth of −1877 m. Based on the test data, the temperature also varies between 94 and 141.7 °C.

The aim of this work is to analyse the oil field, which is still in production, in such a way that a selection of wells can be made that could economically generate electricity from the geothermal aquifer of the oil field. To do this, it is first necessary to identify the wells that are not being used for oil production, the thickness of the geothermal aquifer tapped by these wells and the completion of each well. After a preliminary analysis of the fund of wells, the conditions under which each well represents an economic source of geothermal energy must be determined, i.e., the risk involved in selecting wells for the production of geothermal energy must be determined, taking into account the current completion of the well as a limiting factor (Figure 3).

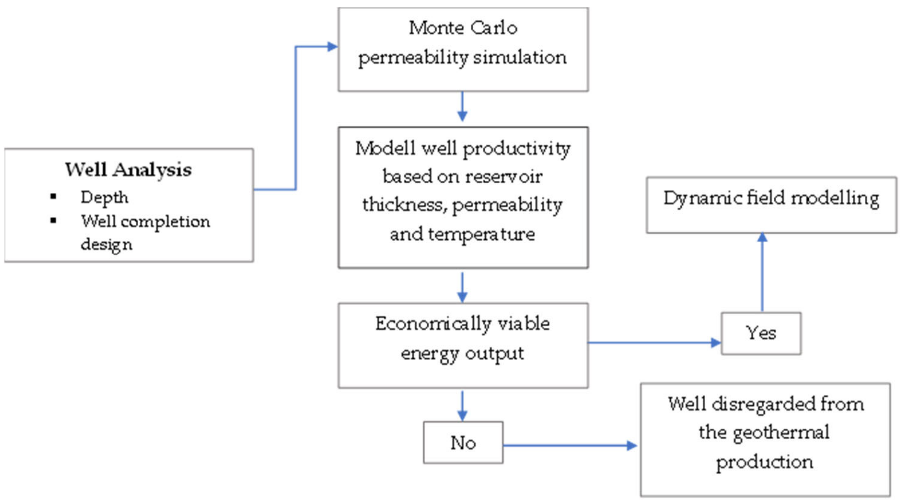


Figure 3. Workflow for the selection of suitable wells from an analysed oil field for use in geothermal energy production.

To investigate the possibility of exploiting the deep aquifer of the oil field, an analysis was carried out on 33 wells that have the status of being monitoring or injection wells. In this way, the analysis of the possibility of using geothermal energy from the oil field aquifer was approached under the assumption that the oil production from shallower reservoirs is undisturbed, while in parallel the geothermal energy of the oil aquifer is used. During the production of the oil, a unique contact was established at −1955 m. When selecting wells for aquifer use, wells whose depths were below the detected absolute oil/water contact level were selected. In this way, 31 wells were selected, of which 22 have the status of being monitoring wells and were included in the analysis as future geothermal production wells, and 9 wells with the status of being injection wells were considered as injection wells for the geothermal reservoir.

In the course of production, after a significant pressure drop and the occurrence of water in the oil production, the aquifer was confirmed, and in order to keep the pressure above the saturation pressure, water flooding was started three years after the start of production with the aim of keeping the reservoir pressure above the saturation pressure of 147 bar. In the absence of data on more recent measurements of static pressure, measurements of the injection wells below the oil–water contact level were analysed (Figure 4). Analysis of the measurements from 2005 and 2006, when the water injection system had already been established for more than 30 years, showed that the pressures at the analysed wells already approached the pressures originally measured at these wells during this period. Since the amount of produced and injected fluid was almost the same, an initial pressure gradient of 0.0961 bar/m was assumed in the analysis [54,57].

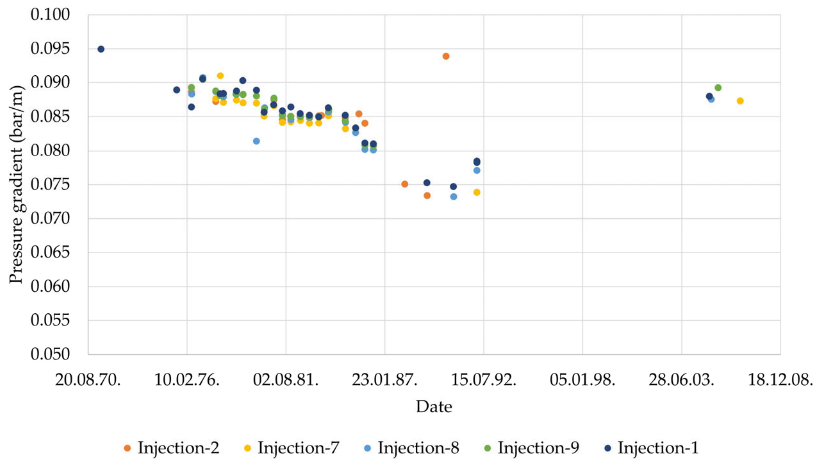


Figure 4. Pressure gradient measurements of injection wells during oil production.

To estimate the temperature at the bottom of the reservoir, the geothermal gradient at the bottom of all wells drilled in the oil field was calculated (Figure 5). The average value of the geothermal gradient was 0.0567 °C/m. For the calculation of the geothermal gradient at the depth of the reservoir, an average ambient temperature of 11.09 °C was used, which corresponds to the average temperature for Osijek, the nearest town to the field, for the period of 1899–2021 [58]. During exploitation, the oil–water contact was found to be at −1.955 m, and during exploitation it was assumed that the contact was increased, resulting in a large number of wells being waterflooded and eventually excluded from production. For the analysis of the possibility of using the oil aquifer for geothermal energy production, the geothermal reservoir was assumed to be at −1955 m and the thickness of the geothermal reservoir was determined for each well from −1955 m to the depth reached by the well. The thickness of the geothermal reservoir at each well ranged from 10 m to over 600 m. It was assumed that the entire interval did not participate in the production, but rather a proportion of 70% per individual well, and in this way, the net reservoir thickness of the reservoir participating in the production of geothermal water was determined. The data used for the characterisation of the geothermal reservoir are listed in Table 1, using the net reservoir thicknesses with an average height of 95.4 m as the baseline values.

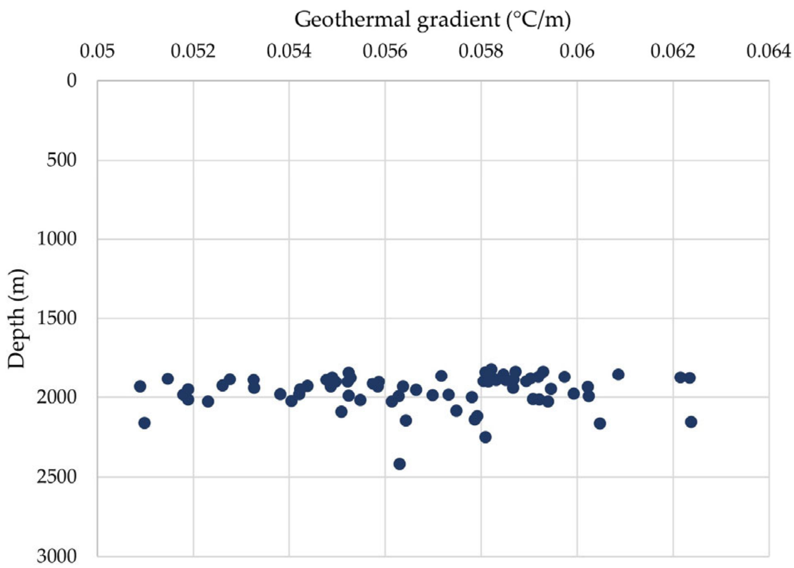


Figure 5. Geothermal gradients across the oil field wells.

Table 1. Geothermal reservoir data.

	Unit		
Mean geothermal reservoir depth	m		2199.06
Reservoir temperature at the mean reservoir depth	°C		135.78
Average reservoir thickness	m		148.66
Reservoir pressure—bottom of the reservoir	bar		211.31
Geothermal gradient	°C/m	0.0567	
Pressure gradient	bar/m	0.0961	

Based on the data of the average values, the Heat in Place of the geothermal aquifer of the analysed oil field was calculated, which was 1.15×10^{18} J.

2.5. Geothermal Brine Flow through Existing Well Completion

The main challenge in the commercial exploitation of geothermal energy from an existing oil field, i.e., through equipment on an existing oil field, is the constraint imposed by the existing well equipment. Namely, in order to reduce the cost of using geothermal energy while utilising abandoned oil wells, it is necessary to conduct an analysis of the existing equipment. The wells in the studied oil field were equipped for oil production and all wells had production intervals covered with 5″ to 5 1/2″ casing, and production was achieved through 2 7/8″ tubing. For the purpose of geothermal water production, the tubing was neglected and production from the casing was assumed. When designing a geothermal field, one is interested in obtaining the highest possible flow. This is achieved by drilling open holes or slotted liners with larger dimensions in the production interval. The objective of this analysis was to explore the possibility of using abandoned oil wells within the framework of existing well completion. Typical well completion is presented in Figure 6 and was used for further brine flow analysis.

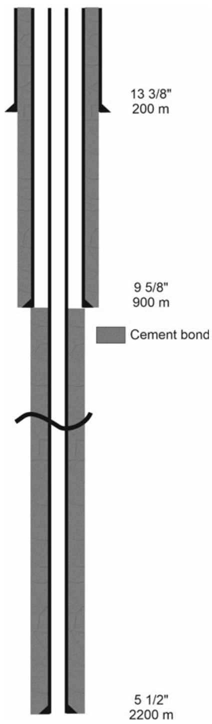


Figure 6. Typical well completion of oil field wells at discussed reservoir.

3. Results and Discussion

The analysis was conducted with a focus on reservoir conditions and the well's production capability under constrained conditions:

- the thickness of the geothermal reservoir accessed by a single well;
- the permeability of the reservoir;
- the gas–liquid ratio of the aquifer.

In this way, the possibility of using the existing infrastructure was analysed and the link with the economic viability of producing geothermal energy from the existing wells through the existing infrastructure was determined, i.e., how individual wells should be selected for the production of geothermal energy.

3.1. Permeability Probability Distribution

A Monte Carlo modelling of the permeability values was carried out to determine the possibility of extraction from a single well. A Beta-PERT distribution (PERT) was created to model the value of the permeability distribution, and to determine the most likely values and obtain a distribution that resembles the real permeability probability distribution. The PERT distribution highlights the most likely values relative to the minimum and maximum estimates and constructs a smooth version of the uniform or triangular distribution. The model was constructed with 50,000 iterations. Since there is no measurement of permeability in the geothermal reservoir itself under the current reservoir conditions, this is how the risk distribution was constructed when selecting a well for geothermal energy extraction. The permeability values were measured using Drill Steam Testing (DST) measurements performed during the drilling of 21 wells in an oil field (Figure 7). Since the geothermal reservoir belongs to the same reservoir as the oil reservoir, only in the water-saturated part, the values were modelled in order to obtain risk-adjusted values for the modelling of the geothermal reservoir. During the development of the oil field, several observations of the occurrence of fractures in the reservoir were recorded in the daily reports of the wells, so we can assume that an extremely increased permeability due to fractures could also occur in a single well (Table 2 and Figure 8). For the purposes of the Monte Carlo modelling, values with a high permeability of over 400 mD were excluded on the assumption that they belonged to the flow achieved through the reservoir fractures.

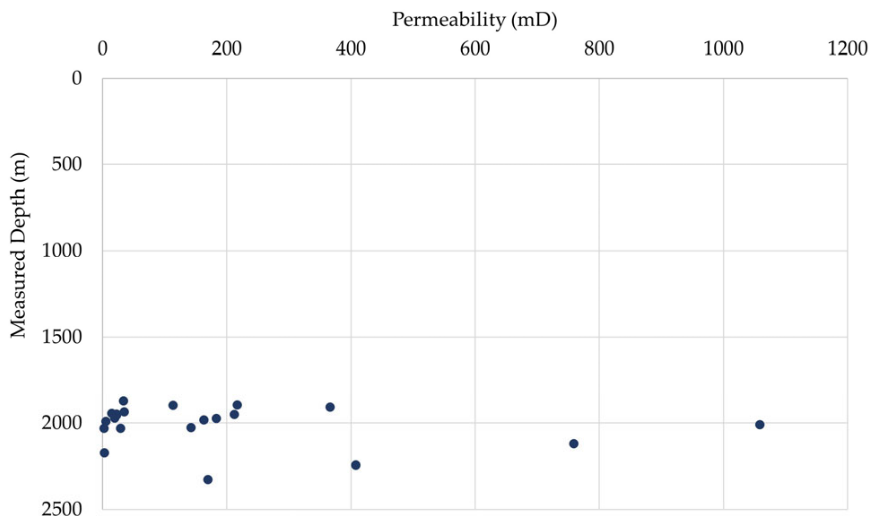


Figure 7. Permeability of wells determined using DST measurements.

Table 2. Permeability Monte Carlo modelling.

	Median	Minimum	Maximum	Standard Deviation
Permeability (mD)	71.62	14.50	363.22	57.54

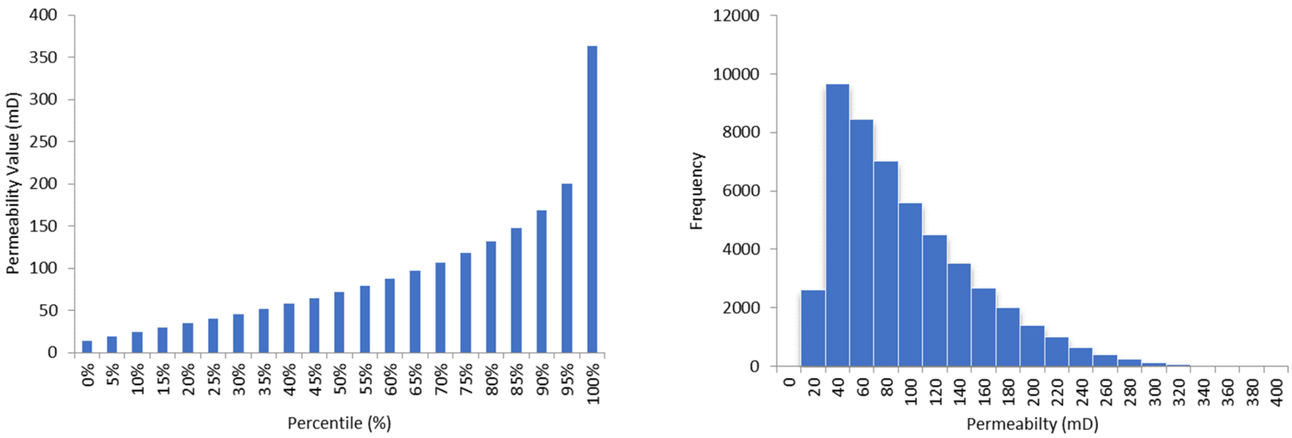
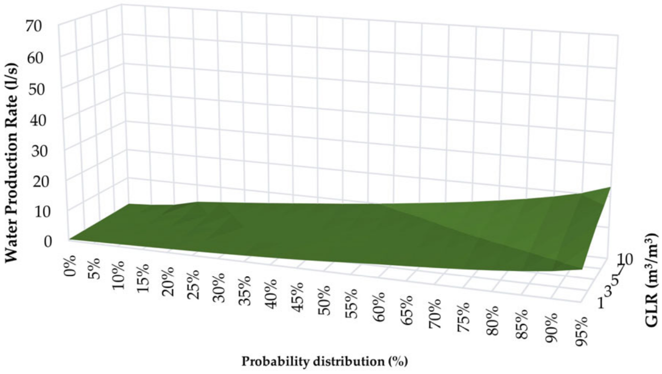


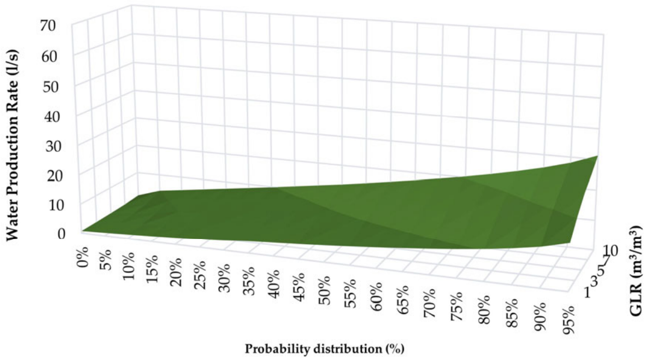
Figure 8. Monte Carlo permeability distribution for the geothermal reservoir.

3.2. Sensitivity Analysis of Brine Flow Considering Well Completion Constraints

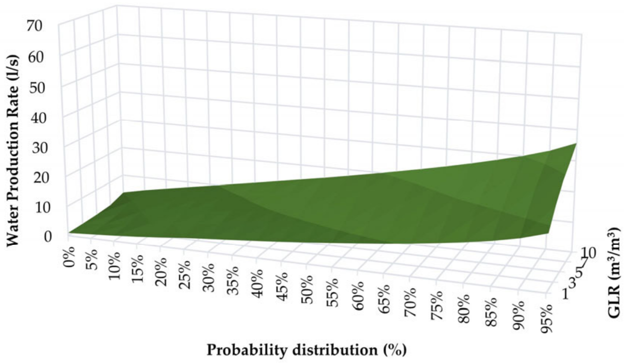
In view of the completion of the wells, the production possibilities of each reservoir in terms of thickness and permeability distribution were analysed in such a way that the sensitivity to the potential benefit and possibility of geothermal energy production per individual well was made in the PROSPER software package [59]. PROSPER is a programme used to optimise wells in the oil industry. This time, the production of brine was adjusted to assume a 99.99% water cut. The programme is used for different configurations of wells to predict flow under reservoir conditions. For the analysis, the characteristics of the oil field geothermal reservoir were used and the values affecting the well productivity were varied. For the equipment, a typical oil well in the field was taken, equipped with 5 1/2″ casing, and the production through the casing was preset. The thickness of the reservoir as a sensitivity parameter for the selection of the wells, i.e., wells that drilled the geothermal aquifer, is important for the selection of future wells in terms of the influence of thickness on flow and temperature [60]. The determination of the heat transfer coefficient is based on empirical data, and its evaluation in the modelling of the future geothermal reservoir is a variable that influences the evaluation [61,62]. In the case of a geothermal system, the determination of the heat transfer coefficient includes the convective heat transfer from the surrounding rock and heat loss via conduction. The heat transfer in the formation depends on the distribution of heat in the formation, the resistance to heat transfer in the well (casing) and the temperature differences [63]. To estimate the value of the heat transfer between the casing and the well and accordingly stabilise the temperature during geothermal extraction, the heat transfer coefficient was calculated with the module PROSPER Enthalpy Balance. The module takes into account heat transfer via conduction, radiation, and forced and free convection. The heat transfer coefficient was calculated using thermodynamic data stored in a user-defined database. The temperature predictions were transient, attributing sensitivity to the flow time of the wells. Using the module, the lithology was described and the production data obtained by modelling the flow through the well were tested, and the heat transfer coefficient for the well was determined using the modelled data. Since the geothermal reservoir is in carbonates, it was assumed that there was a dissolved gas in the reservoir, mainly CO_2. The assumption that CO_2 is present in carbonate reservoirs results from the thermal decomposition of the carbonates, resulting in CO_2 presence [64], which is confirmed by data from other geothermal reservoirs [65]. Assuming the presence of CO_2 in the reservoir, the sensitivity to dissolved CO_2 in the brine was modelled in amounts of 1, 3, 5, 7 and 10 m^3/m^3 (Figure 9a–t).



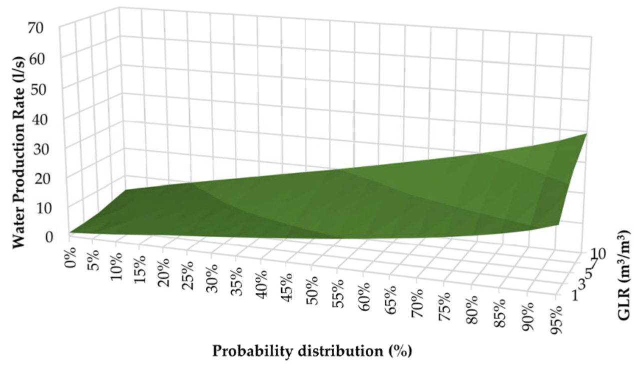
(**a**)



(**b**)

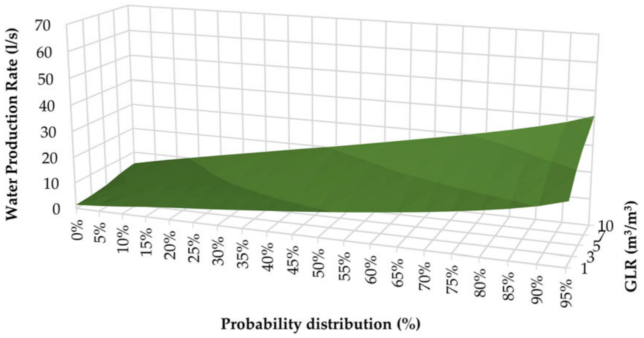


(**c**)

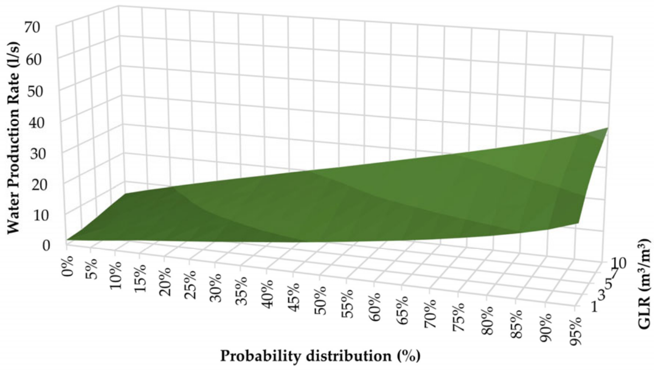


(**d**)

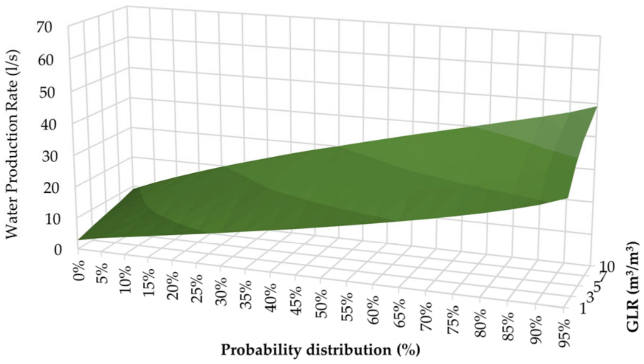
Figure 9. *Cont*.



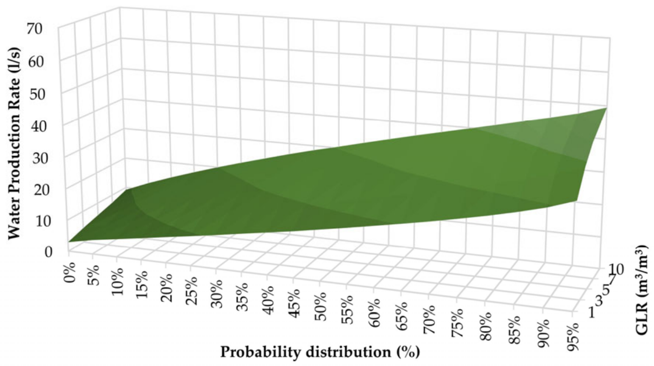
(**e**)



(**f**)

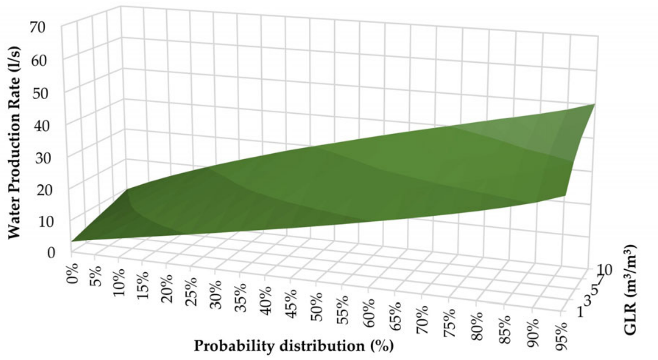


(**g**)

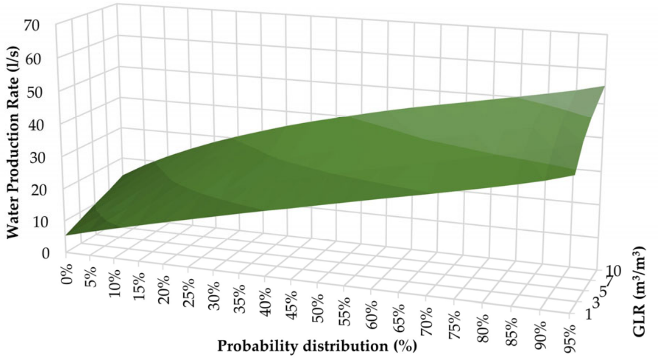


(**h**)

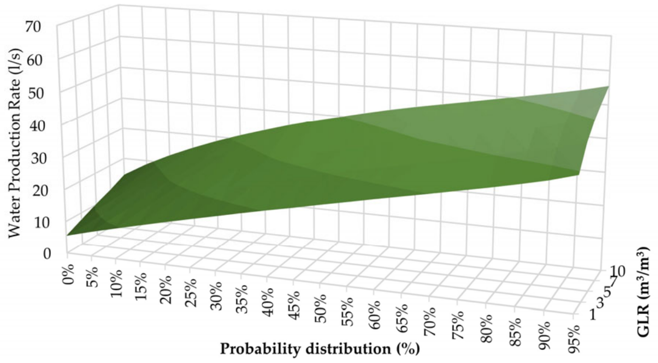
Figure 9. *Cont*.



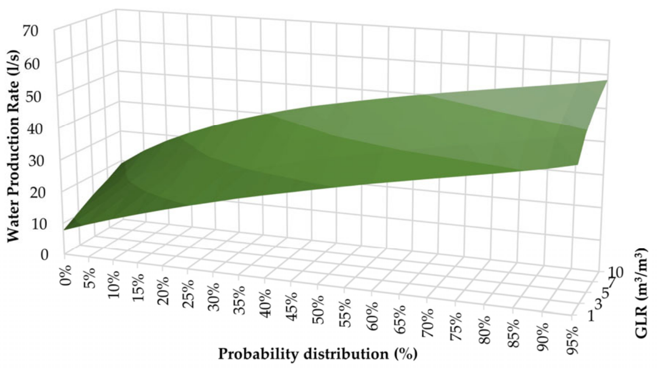
(**i**)



(**j**)

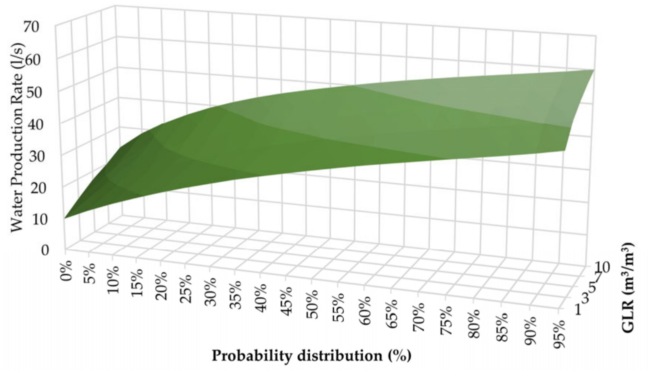


(**k**)

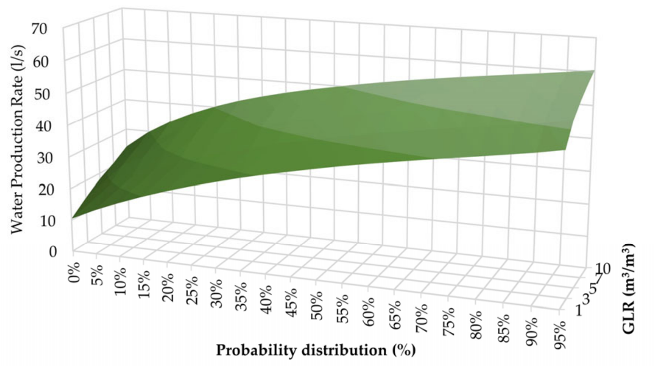


(**l**)

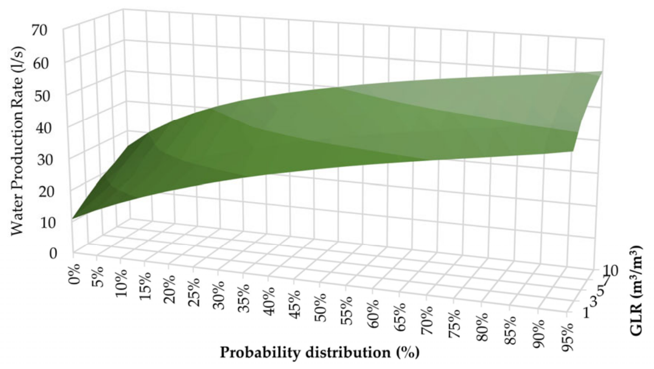
Figure 9. *Cont*.



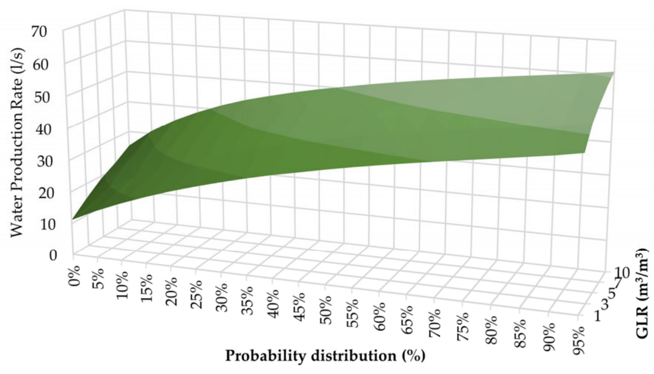
(**m**)



(**n**)

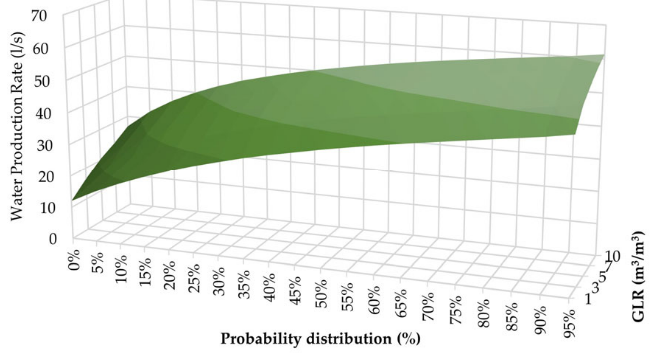


(**o**)

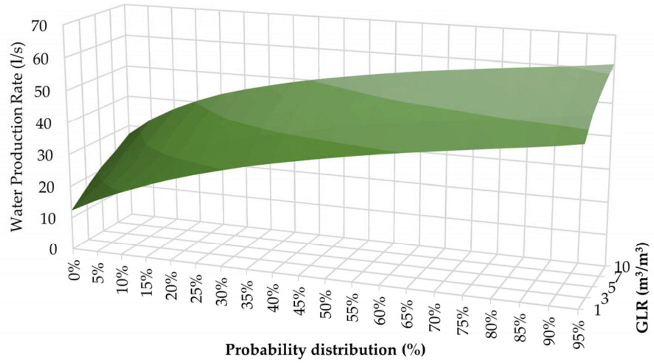


(**p**)

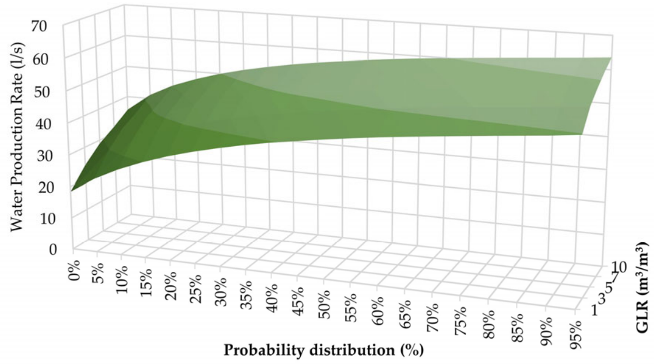
Figure 9. *Cont.*



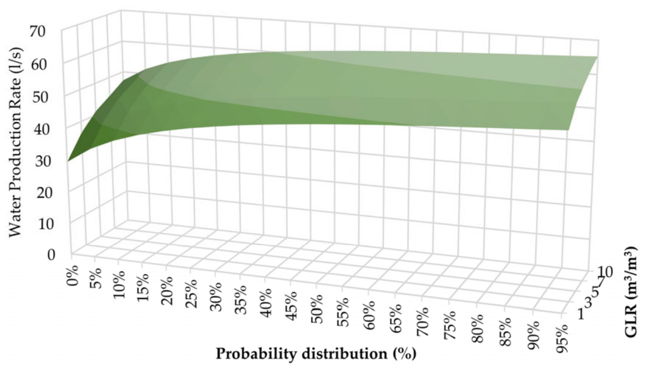
(**q**)



(**r**)



(**s**)

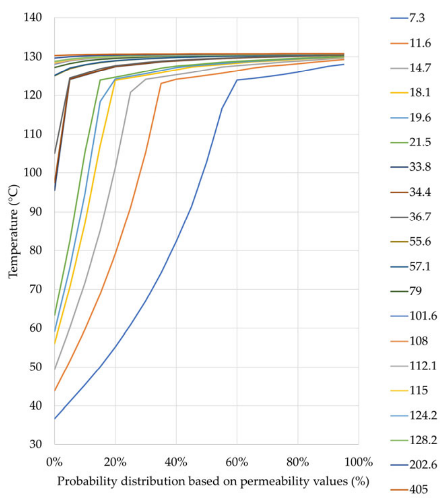


(**t**)

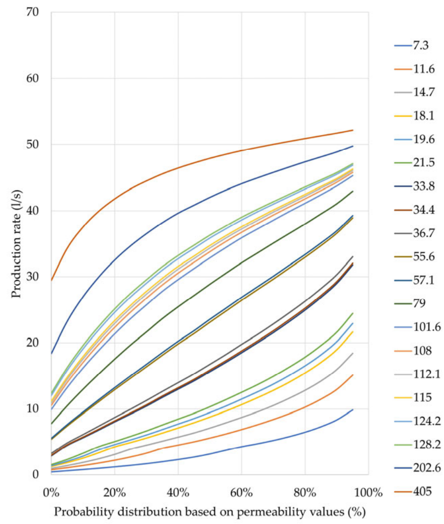
Figure 9. Distribution of the flow probability as a function of the thickness of the reservoir and the proportion of dissolved gas in the brine; (**a**) reservoir thickness, 7.3 m; (**b**) reservoir thickness, 11.6 m; (**c**) reservoir thickness, 14.7 m; (**d**) reservoir thickness, 18.1 m; (**e**) reservoir thickness, 19.6 m; (**f**) reservoir

thickness, 21.5 m; (**g**) reservoir thickness, 33.8 m; (**h**) reservoir thickness, 34.4 m; (**i**) reservoir thickness, 36.7 m; (**j**) reservoir thickness, 55.6 m; (**k**) reservoir thickness, 57.1 m; (**l**) reservoir thickness, 79 m; (**m**) reservoir thickness, 101.6 m; (**n**) reservoir thickness, 108 m; (**o**) reservoir thickness, 112.1 m; (**p**) reservoir thickness, 115 m; (**q**) reservoir thickness, 124.2 m; (**r**) reservoir thickness, 128.2 m; (**s**) reservoir thickness, 202.6 m; (**t**) reservoir thickness, 405 m.

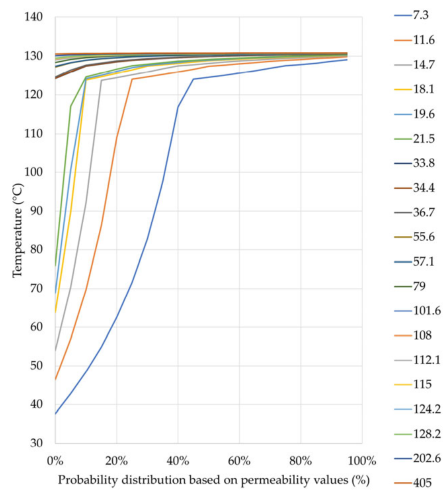
The influence of dissolved gas in the brine is the factor with the greatest uncertainty when it is at a measurement of 1 m^3/m^3 and the risk of low permeability distribution in the well is at 50% (Figure 10). The dissolved gas affects the flow rate and, accordingly, the heat transfer in the well, leading to the rejection of wells with poor permeability characteristics due to low flow rates. Reservoir thickness is a limiting factor in achieving stable wellhead temperature and, accordingly, a risk factor in selecting wells for future geothermal brine production. Temperature stabilisation begins with reservoirs whose thickness exceeds 55 m.



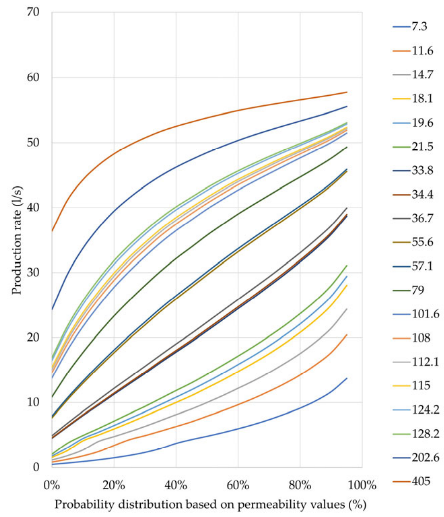
(**a**)



(**b**)



(**c**)



(**d**)

Figure 10. *Cont.*

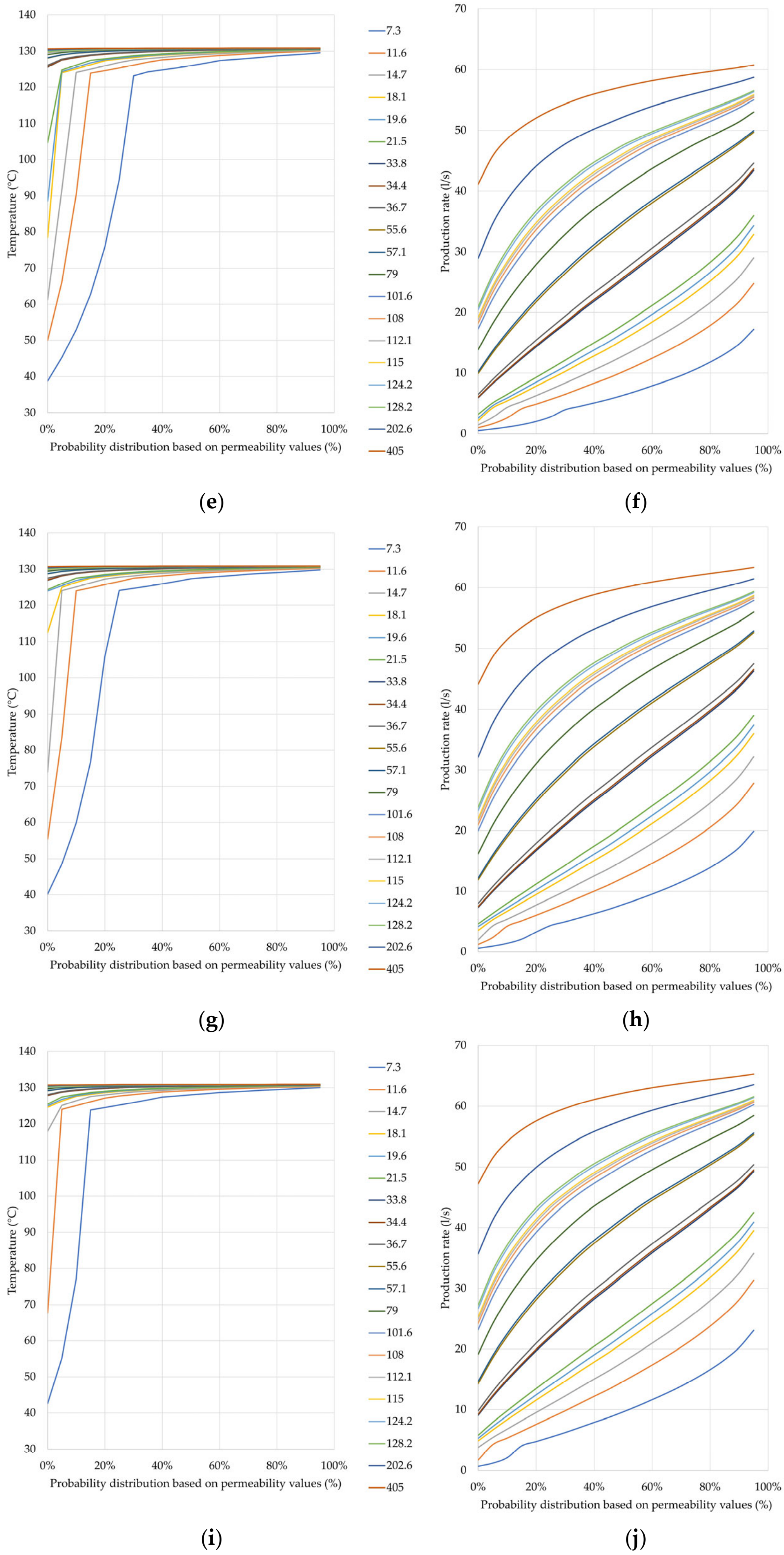


Figure 10. Influence of the gas dissolved in the brine on temperature and flow rate in the well (**a**) GLR-1 m^3/m^3; (**b**) GLR-1 m^3/m^3; (**c**) GLR-3 m^3/m^3; (**d**) GLR-3 m^3/m^3; (**e**) GLR-5 m^3/m^3; (**f**) GLR-5 m^3/m^3; (**g**) GLR-7 m^3/m^3; (**h**) GLR-7 m^3/m^3; (**i**) GLR-10 m^3/m^3; (**j**) GLR-10 m^3/m^3.

3.3. Assessment of the Techno-Economic Potential on a Well Basis

In order to make a selection of wells suitable for the future production of geothermal energy, it is necessary to determine economic parameters that meet economically acceptable criteria. The creation of an economic model of one well is a conservative approach to selection and as such represents a lower risk for future production from several selected wells, together, of course, with a macroeconomic analysis of the economic acceptability of production from the entire field. To determine the output that a single well can produce at a given wellhead temperature and flow rate, the open-source geothermal techno-economic simulator GEOPHIRES v2.0 was used [66]. The programme is used to calculate the current energy production and lifetime energy production, as well as the total levelized energy costs of a geothermal system. It combines reservoir, well and surface plant models, as well as economic and cost models and correlations, to estimate capital costs as well as operation and maintenance costs. The capital and operating costs for the different components of a geothermal system (exploration, well, surface plant) are calculated using integrated correlations. The programme has six possible models built in. For the calculation of power and costs at the level of a single well, a model is used that assumes a hydrothermal reservoir and subcritical ORC power generation. For the calculation of the potential output power, the values for temperature and flow, determined via the sensitivity analysis, were used, while for the economic analysis, the values for the capital and operating costs were used, and the costs of creating new wells were ignored. Considering the proposed cost of capital, the WACC was calculated based on the assumption of dynamic equity and the debt ratio [67,68]. Namely, it was assumed that in the initial phase, due to the high risk of achieving positive effects of the project, the share of equity was 100%, and that, over time, the share of equity would decrease in favour of debt. According to the CAPM method, the ratio of debt to equity affects the final WACC value. For the economic analysis, an average WACC value of 6.30% over 30 years of geothermal energy production was assumed (Figure 11).

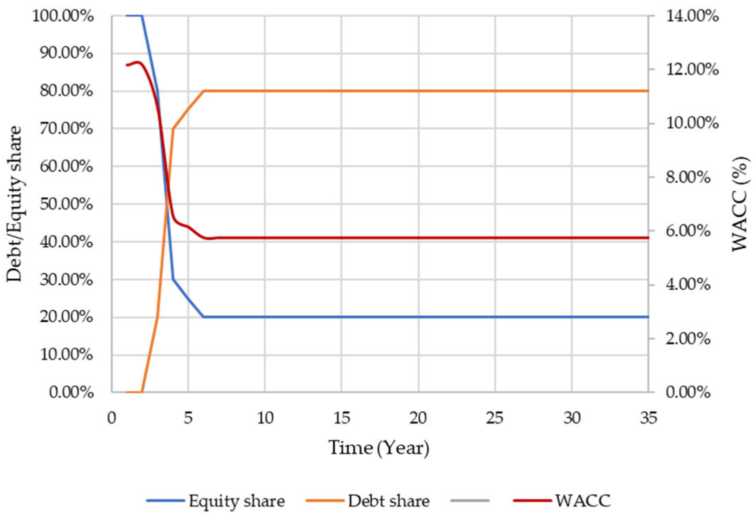


Figure 11. Weighted average cost of capital distribution for geothermal energy production.

The economic analysis determined the range of the possible values of the energy produced and the NPV of a single well. The economically acceptable threshold was determined to be the value of energy produced by a single well that first achieved a positive NPV (Table 3). In this way, the value of the least acceptable produced energy per single well was determined, which was 0.44 MW for a flow rate of 20 L/s and a wellhead temperature of 130 °C (Figure 12).

Table 3. Calculation of the potential output power.

Production Rate (L/s)	Max. Production Temperature (°C)	Max. Electricity Generation (MW)	Increase in Production Rate (%)	Increase in Max. Production Temperature (%)	Increase in Electricity Generation (%)
17	129.40	0.37			
18	129.60	0.39	5.56%	0.15%	5.13%
19	129.80	0.41	5.26%	0.15%	4.88%
20	130.00	0.44	5.00%	0.15%	6.82%
21	130.10	0.46	4.76%	0.08%	4.35%
22	130.20	0.48	4.55%	0.08%	4.17%
23	130.40	0.51	4.35%	0.15%	5.88%
24	130.50	0.53	4.17%	0.08%	3.77%

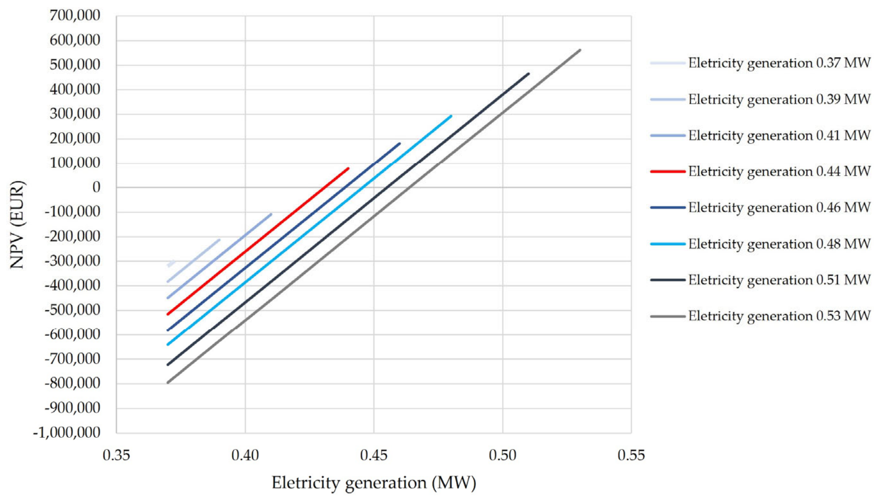
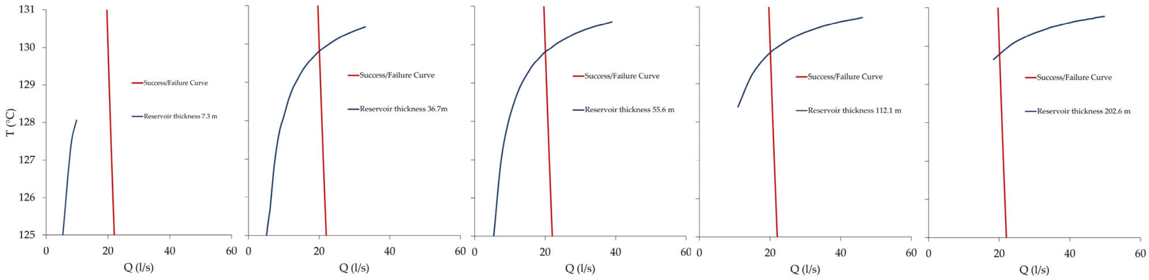
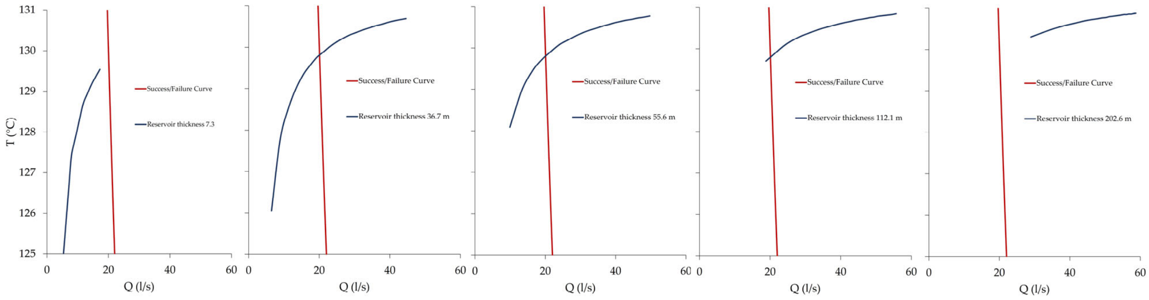


Figure 12. Economic analysis of the potential energy output per individual well.

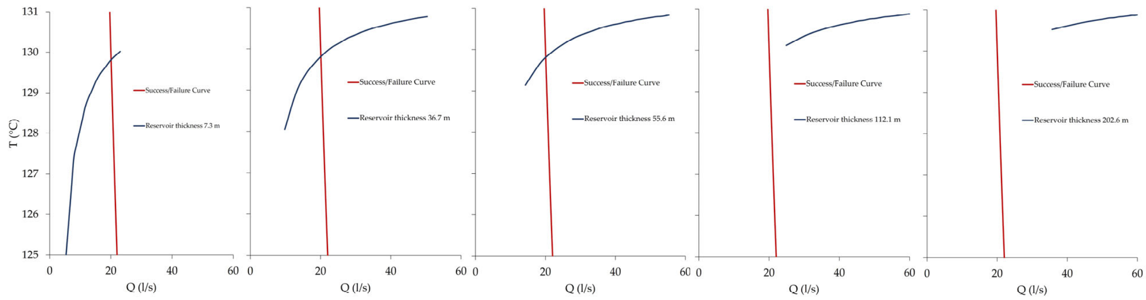
Based on the limit of the economic viability of geothermal energy production per well, a limit was established for the acceptable values of flow rate and well temperature, at which an energy production of 0.44 MW or more was achieved. In this way, a matrix of values for different amounts of dissolved gas and brine was created [69]. Based on the minimum economic viability per well, a project success/failure curve was created, i.e., the temperature and flow rate values at which sufficient performance was achieved for economic viability. The determination of the techno-economic conditions for the selection of wells for the production of geothermal energy involved the sensitivity analysis of the flow rate and temperature achieved, which correspond to the economic cut-off at 50% risk conditions, using the permeability distribution as a risk factor. The sensitivity analysis made it possible to determine the economic profitability of each option under the conditions of different GLRs that can be achieved in the reservoir. Considering the risk distribution as a function of permeability, the conditions under which economic production per well is achieved and the risk is 50% at a gas–liquid ratio of 1 m^3/m^3 are only achieved in reservoirs with a net thickness greater than 55.6 m. As the gas–liquid ratio increases, this limit shifts to the net thickness of the reservoir of 36.7 m at a GLR of 3 m^3/m^3, and in a reservoir with a thickness of less than 21.5 m, there are conditions where the techno-economic conditions for selecting a well are not met even at a GLR of 10 m^3/m^3. From the distribution of the risks for the production of geothermal energy, it can be concluded that the wells whose thickness of the geothermal reservoir, i.e., the net thickness of the reservoir at a single well, is less than 55.6 m should be excluded from further analysis, as their consideration only includes extraction with a higher probability risk associated with the permeability distribution. In this way, a uniform risk in the production of geothermal energy is ensured for all cases of dissolved gas in the brine. Figure 13 shows the achieved ratios of flow and temperature at the wellhead, at different GLR ratios, simulated using PROSPER in relation to the limit of acceptability of these ratios in relation to the success/failure curve modelled via the sensitivity analysis of the economic parameters. For the further analysis of acceptable wells for geothermal production, the thickness of the reservoir was set to a minimum of 55 m.



(**a**)



(**b**)



(**c**)

Figure 13. Economic profitability per well based on the flow rate achieved and the wellhead temperature. (**a**) GLR-1 m^3/m^3; (**b**) GLR-5 m^3/m^3; (**c**) GLR-10 m^3/m^3.

3.4. Reservoir Simulation

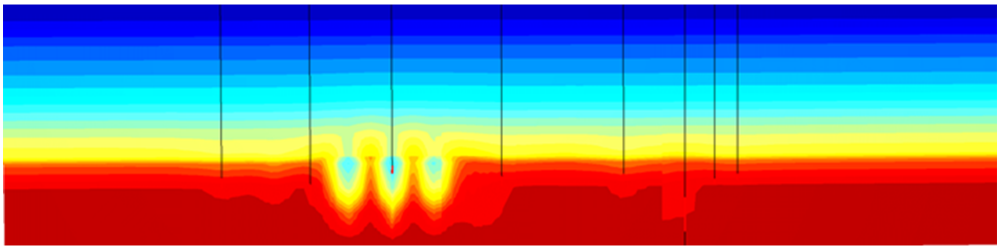
A simulation model was created to provide insight into the total energy produced throughout the field by applying the model of individual well selection based on techno-economic characteristics. Furthermore, the model provided insight into the possibilities of interaction, i.e., the additional selection of wells with regard to their existing location. The TOUGH2 simulator was used to create the model. TOUGH2 is a numerical simulator for non-isothermal flows of multicomponent, multiphase fluids in one-, two- and three-dimensional porous and fractured media [70]. TOUGH2-EOS1 was used for the modelling as the simple geological modelling was approached via Petrasim, an auxiliary tool when using TOUGH2, as the analysis did not include the detailed geological modelling of the field or the detailed distribution of the reservoir properties.

The algorithmic model covered the entire area of about 50 km^2. A polygonal grid was used to model the grid block, with cells of a maximum size of 1×10^5 m^2 and a refinement around the wells of 5000 m^2. According to the geological setting of the field, the model was divided into seven layers corresponding to seven lithological units, each with physical rock properties corresponding to the lithological unit and the depth of the unit. The rock density values were determined via correlation for the Drava Depression [71,72], and based on this, the heat conductivity and specific heat were determined for each layer, i.e., the bed of the model. The parameters were evenly distributed across each layer.

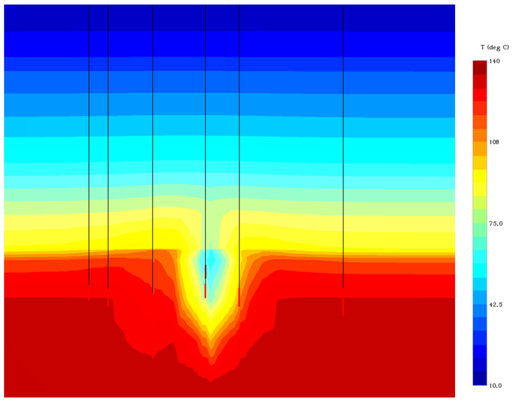
The initial conditions for the model were based on the initial conditions of the oil field (Table 1), where the geothermal gradient was determined as 0.0567 °C/m and the pressure gradient as −0.0961 bar/m. The upper pressure limit was set at 2 bar, which corresponded to the well flow analysis, while the top boundary temperature was set at 11.09 °C [58]. The geothermal reservoir was defined from the oil–water contact at an absolute depth of 1955 m to a final depth of 2850 m. By analysing the behaviour of the temperature inside the observed geothermal reservoir when applying the geothermal gradient, it was shown that the temperature inside the reservoir varies due to the large difference in the depth of the reservoir in the simulated model. Assuming convection conditions within the geothermal reservoir, and in order to bring the results closer to the conditions simulated via the well flow analysis, a constant temperature of 135.78 °C was assumed in the geothermal reservoir, which was determined as the mean temperature of the geothermal reservoir. The permeability of the geothermal reservoir was 71.62 mD, which corresponded to the sensitivity analysis of permeability, with a probability of 50%. The bottom boundary was defined with a constant temperature of 141.7 °C, the highest temperature measured at the bottom of the well at a depth of 2956 m. The simulation time was set to 30 years.

The numerical simulation of a geothermal reservoir is an essential element of the assessment of geothermal potential and involves numerous parameters that define thermodynamic and hydrodynamic relationships [73–76]. Due to the simplicity of the model, some of the parameters in the model were ignored and the model was a simplified version of the geothermal potential of a whole field based on a techno-economic well selection. The aim of the numerical simulation was to study the production from the geothermal reservoir using data obtained through the techno-economic analytical modelling, applying the results of the permeability distribution corresponding to the 50% risk distribution. Since the techno-economic analysis concluded that, with a risk distribution of 50%, wells should be taken where the net thickness of the geothermal reservoir is more than 55 m, 12 of the total 22 wells analysed met the techno-economic conditions for inclusion in the field model. After building the model and analysing the well locations, two production wells (monitoring wells) were excluded from the model because they were located near wells whose depth of penetration into the reservoir and thus production characteristics were more favourable. Given the conditions, two scenarios were created in which the injection parameters were varied. In Scenario 1, ten wells were involved as production wells with a total production of 387.49 L/s, while seven wells were involved as injection wells, and the injection was evenly distributed among the wells and was 55.35 L/s per well, while the enthalpy of the injected brine corresponded to a temperature of 60 °C. The injection wells have open perforations for injection from the shallowest depth of 1975 m to the deepest depth reached by the well, which is −2460 m. To analyse the impact of injection on the total potentially recoverable energy, Scenario 2 simulated production with 10 production wells at the same production rate as Scenario 1, but the injection was simulated through four wells and the injected brine was simulated to the deeper parts of the reservoir. In this way, the shallowest injection well was set to a depth of −2199 m.

The simulation of the reservoir conditions in Scenario 1 showed that the cold front intrusion covered a larger part of the reservoir (Figure 14a,b), while the total field energy in the first year of production was 230.011×10^6 J/s, while the field energy decreased to 221.346×10^6 J/s after 30 years of production. In Scenario 2, which simulated water intrusion into the deeper part of the reservoir through fewer wells, the cold front intrusion covered a smaller part of the reservoir, i.e., the distribution of the cold front was less dominant around the injection wells themselves. The distribution of the cold front had an impact on the total energy of the field. The first year of production resulted in the same field energy as Scenario 1, while the total energy after 30 years of production was 221.456×10^6 J/s (Figure 15a,b). The comparison of Scenarios 1 and 2 shows that the total energy of the reservoir is influenced by the injection depth, notwithstanding the fact that, in Scenario 2, a higher flow through the injection wells had to be simulated. Furthermore, the energy potential of the reservoir decreased by 3.767% in Scenario 1, while the energy in Scenario 2 decreased by 3.719% over a period of 30 years, which in total influence the economic viability of the geothermal potential.

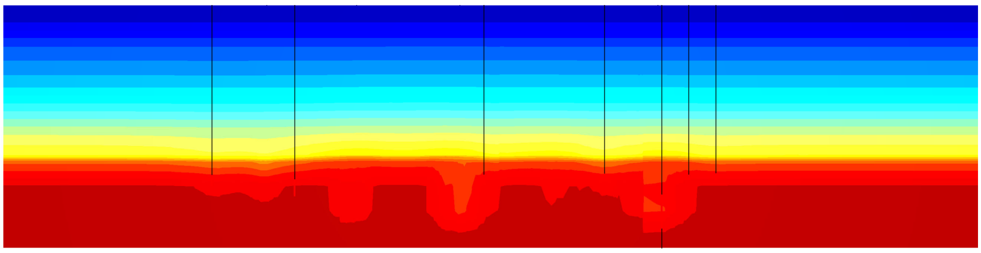


(**a**)

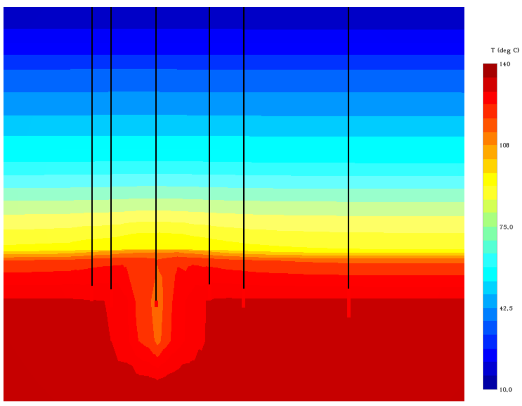


(**b**)

Figure 14. Cold front distribution in Scenario 1 after 30 years of production ((**a**) front view; (**b**) side view).



(**a**)



(**b**)

Figure 15. Cold front distribution in Scenario 2 after 30 years of production ((**a**) front view; (**b**) side view).

4. Conclusions

The conversion of oil fields into geothermal energy is a topic of great interest and therefore attracts much attention. The knowledge acquired in the exploration and exploitation of hydrocarbons, and especially the infrastructure, become valuable assets in the use of geothermal energy. Since conversion mainly involves low- and medium-enthalpy geothermal aquifers, the available resources must be optimally utilised. When we talk about the conversion of hydrocarbon fields into geothermal energy, a clear plan to analyse numerous parameters is required to maximise the production of geothermal energy. Apart from the condition of the reservoir, i.e., the parameters of pressure, permeability, porosity and temperature, the completion of the wells is one of the main difficulties in converting oil wells into geothermal energy wells. When analysing the technical conditions that enable the flow, it was concluded that the reservoir cannot develop its full potential due to the limitations in the well completion, so due attention must be paid to the modelling of the reservoir, that is, the net thickness of the reservoir that will participate in the future production of geothermal brine. Therefore, for low- to medium-enthalpy geothermal reservoirs such as those presented in this paper, the focus of the analysis must be on the potential flow through the casing. Flow, in addition to well temperature, affects the economic valuation of a project, because if flow increases by only 5%, geothermal production through a single well increases by 6.82%, so the well reaches an economic cut-off, i.e., the conversion of oil in the well receives its economic value. Besides the individual analysis of each well and the selection of the best candidates, only the simulation of the geothermal production of the whole field provides information about the interaction of production and injection wells, and the energy potential of the reservoir. The conversion of oil fields to geothermal fields is a complex problem, both in terms of reservoir parameters and well completion, and in terms of the overall economic effect of the whole field, which is influenced by the behaviour of the reservoir in terms of well doublet placement and the possibility of reaching more favourable parts of the reservoir. The economic analysis for the whole field should be confronted with the analysis of the costs of abandoning the oil field and reducing CO_2 emissions. Only in this respect would the profitability of the project be comparable to the benefits of the transformation. Therefore, further studies should be conducted to assess the contribution of such transformations to the green transition.

Author Contributions: Conceptualization: M.T.; methodology: M.T. and T.K.; simulations: M.T.; validation: T.K.; writing—original draft and review: M.T. and T.K.; supervision: T.K.; investigation: M.T. All authors have read and agreed to the published version of the manuscript.

Funding: The APC was partially funded by the European Commission's Interreg CENTRAL EUROPE programme (project TRANSGEO, grant number CE0100071) and partially by the Development fund of the Faculty of Mining, Geology and Petroleum Engineering, Zagreb, Croatia.

Data Availability Statement: All data used in the analysis are the property of the Republic of Croatia and were obtained from the database of the Croatian Hydrocarbon Agency, and may be used for scientific research purposes.

Acknowledgments: The Faculty of Mining, Geology and Petroleum Engineering, University of Zagreb, Croatia, facilitated the use of the software package PROSPER, while the Croatian Hydrocarbon Agency facilitated the use of the software package TOUGH2.

Conflicts of Interest: The authors declare no conflict of interest.

References

1. IRENA. *Renewable Capacity Statistics 2023*; International Renewable Energy Agency: Abu Dhabi, United Arab Emirates, 2023.
2. Sveinbjornsson, B.M.; Thorhallsson, S. Cost and effectiveness of geothermal drilling. In Proceedings of the SIMS 53rd Conference, Reykjavik, Iceland, 4–6 October 2012.
3. Augustine, C.; Tester, J.W.; Anderson, B. A Comparison of Geothermal with Oil and Gas Well Drilling Costs. In Proceedings of the Thirty-First Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, USA, 30 January–1 February 2006.

4. Lukawski, M.Z.; Anderson, B.J.; Augustine, C.; Capuano, L.; Beckers, K.F.; Livesay, B.; Tester, J.W. Cost Analysis of Oil, Gas, and Geothermal Well Drilling. *J. Pet. Sci. Eng.* **2014**, *118*, 1–14. [CrossRef]
5. Kaplanoğlu, M.A.; Baba, A.; Akkurt, G.G. Use of Abandoned Oil Wells in Geothermal Systems in Turkey. *Geomech. Geophys. Geo-Energy Geo-Resour.* **2019**, *6*, 1. [CrossRef]
6. Wang, S.; Yan, J.; Li, F.; Hu, J.; Li, K. Exploitation and Utilization of Oilfield Geothermal Resources in China. *Energies* **2016**, *9*, 798. [CrossRef]
7. Leitch, A.L.; Haley, B.; Hastings-Simon, S. Can the Oil and Gas Sector Enable Geothermal Technologies? Socio-Technical Opportunities and Complementarity Failures in Alberta, Canada. *Energy Policy* **2019**, *125*, 384–395. [CrossRef]
8. Nadkarni, K.; Lefsrud, L.; Schiffner, D.; Banks, J. Converting Oil Wells to Geothermal Resources: Roadmaps and Roadblocks for Energy Transformation. *Energy Policy* **2022**, *161*, 112705. [CrossRef]
9. Mahmoodpour, S.; Singh, M.; Mahyapour, R.; Tangirala, S.K.; Bär, K.; Sass, I. Numerical Simulation of Thermo-Hydro-Mechanical Processes at Soultz-Sous-Forêts. *Energies* **2022**, *15*, 9285. [CrossRef]
10. Singh, M.; Mahmoodpour, S.; Ershadnia, R.; Soltanian, M.R.; Sass, I. Comparative Study on Heat Extraction from Soultz-Sous-Forêts Geothermal Field Using Supercritical Carbon Dioxide and Water as the Working Fluid. *Energy* **2023**, *266*, 126388. [CrossRef]
11. Fridleifsson, I.B. Geothermal Energy for the Benefit of the People. *Renew. Sustain. Energy Rev.* **2001**, *5*, 299–312. [CrossRef]
12. Lund, J.W.; Toth, A.N. Direct utilization of Geothermal Energy 2020 Worldwide Review. In Proceedings of the World Geothermal Congress 2020+1, Reykjavik, Iceland, 24–27 October 2021.
13. Di Pippo, R. *Geothermal Power Plants, Principles, Applications, Case Studies and Environmental Impact. Elements of Thermodynamics*; Butterworth-Heinemann: Waltham, MA, USA, 2016; pp. 715–726. [CrossRef]
14. Lindal, B. Industrial and other applications of geothermal energy. In *Geothermal Energy*; UNESCO: New York, NY, USA, 1973; pp. 135–148.
15. Hranić, J.; Raos, S.; Leoutre, E.; Rajšl, I. Two-Stage Geothermal Well Clustering for Oil-to-Water Conversion on Mature Oil Fields. *Geosciences* **2021**, *11*, 470. [CrossRef]
16. Kurnia, J.C.; Shatri, M.S.; Putra, Z.A.; Zaini, J.; Caesarendra, W.; Sasmito, A.P. Geothermal Energy Extraction Using Abandoned Oil and Gas Wells: Techno-Economicand Policy Review. *Int. J. Energy Res.* **2021**, *46*, 28–60. [CrossRef]
17. Westphal, D.; Weijermars, R. Economic Appraisal and Scoping of Geothermal Energy Extraction Projects Using Depleted Hydrocarbon Wells. *Energy Strategy Rev.* **2018**, *22*, 348–364. [CrossRef]
18. Li, K.; Sun, W. Modified Method for Estimating Geothermal Resources in Oil and Gas Reservoirs. *Math. Geosci.* **2014**, *47*, 105–117. [CrossRef]
19. Nian, Y.-L.; Cheng, W.-L. Insights into Geothermal Utilization of Abandoned Oil and Gas Wells. *Renew. Sustain. Energy Rev.* **2018**, *87*, 44–60. [CrossRef]
20. Wang, K.; Yuan, B.; Ji, G.; Wu, X. A Comprehensive Review of Geothermal Energy Extraction and Utilization in Oilfields. *J. Pet. Sci. Eng.* **2018**, *168*, 465–477. [CrossRef]
21. Caulk, R.; Tomac, I. Reuse of Abandoned Oil and Gas Wells for Geothermal Energy Production. *Renew. Energy* **2017**, *112*, 388–397. [CrossRef]
22. Macenić, M.; Kurevija, T. Revitalization of Abandoned Oil and Gas Wells for a Geothermal Heat Exploitation by Means of Closed Circulation: Case Study of the Deep Dry Well Pčelić-1. *Interpretation* **2018**, *6*, SB1–SB9. [CrossRef]
23. Bu, X.; Ma, W.; Li, H. Geothermal Energy Production Utilizing Abandoned Oil and Gas Wells. *Renew. Energy* **2012**, *41*, 80–85. [CrossRef]
24. Davis, A.; Michaelides, E.E. Geothermal Power Production from Abandoned Oil Wells. *Energy* **2009**, *34*, 866–872. [CrossRef]
25. Gharibi, S.; Mortezazadeh, E.; Bodi, S.J.H.A.; Vatani, A. Feasibility Study of Geothermal Heat Extraction from Abandoned Oil Wells Using a U-Tube Heat Exchanger. *Energy* **2018**, *153*, 554–567. [CrossRef]
26. Wang, K.; Liu, J.; Wu, X. Downhole Geothermal Power Generation in Oil and Gas Wells. *Geothermics* **2018**, *76*, 141–148. [CrossRef]
27. Santos, L.; Taleghani, A.D.; Elsworth, D. Repurposing Abandoned Wells for Geothermal Energy: Current Status and Future Prospects. *Renew. Energy* **2022**, *194*, 1288–1302. [CrossRef]
28. Liu, X.; Falcone, G.; Alimonti, C. A Systematic Study of Harnessing Low-Temperature Geothermal Energy from Oil and Gas Reservoirs. *Energy* **2018**, *142*, 346–355. [CrossRef]
29. Dickson, M.H.; Fanelli, M. Small Geothermal Resources: A Review. *Energy Sources* **1994**, *16*, 349–376. [CrossRef]
30. Lee, K.C. Classification of Geothermal Resources by Exergy. *Geothermics* **2001**, *30*, 431–442. [CrossRef]
31. Rybach, L. Classification of Geothermal Resources by Potential. *Geotherm. Energy Sci.* **2015**, *3*, 13–17. [CrossRef]
32. Muffler, P.; Cataldi, R. Methods for Regional Assessment of Geothermal Resources. *Geothermics* **1978**, *7*, 53–89. [CrossRef]
33. Williams, C.F.; Reed, M.J.; Robert, H.M. *A Review of Methods Applied by the U.S. Geological Survey in the Assessment of Identified Geothermal Resources*; Open-File Report 2008–1296; U.S. Geological Survey: Reston, VA, USA, 2008; 30p.
34. Muffler, L.J.P. Assesment of Geothermal Resources of the United States. *Geol. Surv. Circ.* **1978**, *790*, 163.
35. Song, J.; Loo, P.; Teo, J.; Markides, C.N. Thermo-Economic Optimization of Organic Rankine Cycle (ORC) Systems for Geothermal Power Generation: A Comparative Study of System Configurations. *Front. Energy Res.* **2020**, *8*. [CrossRef]
36. Astolfi, M.; Romano, M.C.; Bombarda, P.; Macchi, E. Binary ORC (Organic Rankine Cycles) Power Plants for the Exploitation of Medium–Low Temperature Geothermal Sources—Part A: Thermodynamic Optimization. *Energy* **2014**, *66*, 423–434. [CrossRef]

37. DiPippo, R. Second Law Assessment of Binary Plants Generating Power from Low-Temperature Geothermal Fluids. *Geothermics* **2004**, *33*, 565–586. [CrossRef]
38. Hijriawan, M.; Pambudi, N.A.; Biddinika, M.K.; Wijayanto, D.S.; Kuncoro, I.W.; Rudiyanto, B.; Wibowo, K.M. Organic Rankine Cycle (ORC) in Geothermal Power Plants. *J. Phys.* **2019**, *1402*, 044064. [CrossRef]
39. Milora, S.L.; Tester, J.W. *Geothermal Energy as a Source of Electric Power*; MIT: New York, NY, USA, 1976; p. 186.
40. Matanović, D. *Cijevne Alatke pri Opremanju i Održavanju Bušotina (Tubulars in Completion and Workover Operations)*; Faculty of Mining, Geology and Petroleum Engineering, University of Zagreb: Zagreb, Croatia, 1999.
41. Zarrouk, S.J.; McLean, K. Geothermal Wells. In *Geothermal Well Test Analysis*; Elsevier: London, UK, 2019; pp. 39–61. [CrossRef]
42. Renpu, W. Well Completion Mode Selection. In *Advanced Well Completion Engineering*, 3rd ed.; Elsevier: Waltham, MA, USA, 2011; pp. 75–116. [CrossRef]
43. Teodoriu, C.; Falcone, G. Comparing Completion Design in Hydrocarbon and Geothermal Wells: The Need to Evaluate the Integrity of Casing Connections Subject to Thermal Stresses. *Geothermics* **2009**, *38*, 238–246. [CrossRef]
44. Kipsang, C. Cost Model for Geothermal Wells. In Proceedings of the World Geothermal Congress, Melbourne, Australia, 19–25 April 2015.
45. Lukawski, M.Z.; Silverman, R.; Tester, J.W. Uncertainty Analysis of Geothermal Well Drilling and Completion Costs. *Geothermics* **2016**, *64*, 382–391. [CrossRef]
46. Franc-Dąbrowska, J.; Mądra-Sawicka, M.; Milewska, A. Energy Sector Risk and Cost of Capital Assessment—Companies and Investors Perspective. *Energies* **2021**, *14*, 1613. [CrossRef]
47. Simshauser, P. The Cost of Capital for Power Generation in Atypical Capital Market Conditions. *Econ. Anal. Policy* **2014**, *44*, 184–201. [CrossRef]
48. Sharpe, W.F. Capital Asset Prices: A Theory of Market Equilibrium under Conditions of Risk. *J. Financ.* **1964**, *19*, 425–442. [CrossRef]
49. Fama, E.F.; French, K.R. The Capital Asset Pricing Model: Theory and Evidence. *J. Econ. Perspect.* **2004**, *18*, 25–46. [CrossRef]
50. Horvathova, J.; Mokrišova, M. Application of CAPM for the Evaluation of Cost of Equity. 2014. Available online: https://exclusiveejournal.sk/files/4-2014/3-horvathova-mokrisova.pdf (accessed on 15 May 2023).
51. Energy Development Strategy of the Republic of Croatia until 2030 with a Look at 2050. 2020. Available online: https://narodne-novine.nn.hr/clanci/sluzbeni/2020_03_25_602.html (accessed on 25 April 2023).
52. Velić, J.; Malvić, T.; Cvetković, M.; Vrbanac, B. Reservoir Geology, Hydrocarbon Reserves and Production in the Croatian Part of the Pannonian Basin. *Geol. Croat.* **2012**, *65*, 91–101. [CrossRef]
53. Lučić, D.; Saftić, B.; Krizmanić, K.; Prelogović, E.; Britvić, V.; Mesić, I.; Tadej, J. The Neogene Evolution and Hydrocarbon Potential of the Pannonian Basin in Croatia. *Mar. Pet. Geol.* **2001**, *18*, 133–147. [CrossRef]
54. INA. *Elaborat o Rezervama Polja Beničanci (Reserves Study of Beničanci Field)*; Original documentation provided by CHA; INA: Zagreb, Croatia, 1990.
55. Pleić, M.; Futivić, I. 3D Seismic Interpretation of the Beničanci Oil Field. *Naftaplin* **2002**, *19*, 17–25.
56. Malvić, T. Kriging, Cokriging or Stochastical Simulations, and the Choice between Deterministic or Sequential Approaches. *Geol. Croat.* **2008**, *61*, 37–47. [CrossRef]
57. INA—Industrija Nafte, d.d. *Elaborat o Rezervama Ugljikovodika Eksploatacijskog Polja Beničanci (Reserves Study of Beničanci Hydrocarbon Field)*; Original documentation provided by CHA; INA: Zagreb, Croatia, 2017.
58. Croatian Meteorological and Hydrological Service. 2021. Available online: https://meteo.hr/klima.php?section=klima_podaci&param=k1&Grad=osijek (accessed on 15 April 2023).
59. Petroleum Experts. *PROSPER User's Manual*; Scantron: Eagan, MN, USA, 2013.
60. Poulsen, S.E.; Balling, N.; Nielsen, S.B. A Parametric Study of the Thermal Recharge of Low Enthalpy Geothermal Reservoirs. *Geothermics* **2015**, *53*, 464–478. [CrossRef]
61. Zhao, Z. On the Heat Transfer Coefficient between Rock Fracture Walls and Flowing Fluid. *Comput. Geotech.* **2014**, *59*, 105–111. [CrossRef]
62. Kędzierski, P.; Nagórski, Z.; Niezgoda, T. Determination of Local Values of Heat Transfer Coefficient in Geothermal Models with Internal Functions Method. *Renew. Energy* **2016**, *92*, 506–516. [CrossRef]
63. Kolo, I.; Sousa, R.; Zhang, T. Heat Transmission in a Geothermal Wellbore: Modelling and Application. 2014. In Proceedings of the 19th Australasian Fluid Mechanics Conference, Melbourne, Australia, 8–11 December 2014.
64. Barić, G. Organic Geochemistry in the Rationalization of Oil and Gas Exploration and Production. *Geol. Croat.* **1996**, *49*, 191–195. Available online: https://hrcak.srce.hr/61166 (accessed on 10 June 2023).
65. Predovan, M.; Blecich, P. Thermodynamic Analysis of a 17.5 MW Geothermal Power Plant Operating with Binary Organic Rankine Cycle. *Int. Sci. J. Mach. Technol. Mater.* **2021**, *15*, 49–52. Available online: https://stumejournals.com/journals/mtm/2021/2/49 (accessed on 1 May 2023).
66. Beckers, K.F.; McCabe, K. *GEOPHIRES v2.0*; OSTI OAI; US Department of Energy Office of Scientific and Technical Information: Washington, DC, USA, 2020. [CrossRef]
67. Wall, A.M.; Dobson, P.F.; Thomas, H. Geothermal Costs of Capital: Relating Market Valuation to Project Risk and Technology. *Geotherm. Resour. Counc. Trans.* **2017**, *41*, 45–61.

68. Kustra, A.; Lorenc, S. Financial Balance Analysis of Geothermal Companies in Poland Based on Managerial Cash Flows. *Energies* **2021**, *14*, 7885. [CrossRef]
69. Davaux, M.; Ungemach, P.; Antics, M.; Naville, C. Geothermal derisking. How to learn and succeed from failure stories. In Proceedings of the European Geothermal Congress, Den Haag, The Netherlands, 11–14 June 2019.
70. Pruess, K.; Oldenburg, C.; Moridis, G. *TOUGH2 Use's Guide*, Version 2; Lawrence Berkeley National Laboratory: Berkeley, CA, USA, 2012.
71. Jelić, K. Thermodynamic Characteristics of Sedimentary Complex of SW Part of Pannonian Basin (in Croatian: Termodinamicke Osobine Sedimentnog Kompleksa Jugozapadnog Dijela Panonskog Bazena). Ph.D. Thesis, Faculty of Mining, Geology and Petroleum Engineering, University of Zagreb, Zagreb, Croatia, 1979.
72. Jelić, K.; Kevrić, I.; Krasić, O. Temperatura i Toplinski Tok u Tlu Hrvatske. In Proceedings of the First Croatian Geological Congress, Zagreb, Croatia, 18–21 October 1995; pp. 245–249.
73. Mahmoodpour, S.; Singh, M.; Turan, A.; Bär, K.; Sass, I. Simulations and Global Sensitivity Analysis of the Thermo-Hydraulic-Mechanical Processes in a Fractured Geothermal Reservoir. *Energy* **2022**, *247*, 123511. [CrossRef]
74. Mahmoodpour, S.; Singh, M.; Bär, K.; Sass, I. Thermo-Hydro-Mechanical Modeling of an Enhanced Geothermal System in a Fractured Reservoir Using Carbon Dioxide as Heat Transmission Fluid—A Sensitivity Investigation. *Energy* **2022**, *254*, 124266. [CrossRef]
75. Zayed, M.E.; Shboul, B.; Yin, H.; Zhao, J.; Zayed, A.A.A. Recent Advances in Geothermal Energy Reservoirs Modeling: Challenges and Potential of Thermo-Fluid Integrated Models for Reservoir Heat Extraction and Geothermal Energy Piles Design. *J. Energy Storage* **2023**, *62*, 106835. [CrossRef]
76. Schulte, D.O.; Arnold, D.; Geiger, S.; Demyanov, V.; Sass, I. Multi-Objective Optimization under Uncertainty of Geothermal Reservoirs Using Experimental Design-Based Proxy Models. *Geothermics* **2020**, *86*, 101792. [CrossRef]

3. DISCUSSION

The topic of this dissertation was the creation of a model to enable the assessment of the geothermal potential of the Croatian part of the Pannonian Basin. A review of the existing literature and previous research has shown that this part has an increased geothermal gradient. At a time when demand for renewable energy sources is increasing, it is necessary to utilise all renewable energy sources with maximum consideration of their specific characteristics. Geothermal energy as a renewable energy source has its own specificity, as it is available at any time and independent of external influences. In the absence of sufficient systematic research for the Republic of Croatia in the direction of the potential of geothermal energy, it became necessary to analyse the current state of exploration and use of geothermal energy, as well as an analysis of the potential located outside the areas that are currently subject to certain contractual obligations. Considering the history of exploration and exploitation of hydrocarbons and the numerous data that the Republic of Croatia has in terms of recorded seismic data and the inventory of wells, as well as oil and gas production, it is also necessary to analyse the potential of oil and gas aquifers with an increased geothermal gradient. In the future, when production from these fields ceases, the aquifer's energy could be used for the production of renewable energy sources, i.e. geothermal energy. Based on the above, the main objectives of this dissertation were determined as follows:

1) Definition of the geological, petrophysical, thermodynamic and technical parameters required for modelling the heat potential of geothermal energy from geothermal reservoirs.
2) The creation of a model for estimating the thermal potential of geothermal energy in the Croatian part of the Pannonian Basin and an analysis of the currently used geothermal potential.
3) The quantification of the possibility of using the estimated thermal energy in the energy process (thermal energy/electrical energy).
4) The creation of a model for the conversion of hydrocarbon fields into the use of geothermal water from deep aquifers and the testing of the hypotheses to be proven by this research were established.

Hypotheses #1 -The geothermal gradient of the Croatian part of the Pannonian Basin offers better opportunities for the use of geothermal energy for energy conversion.

The Croatian part of the Pannonian Basin (CPB) is divided into four main depressions: Mura, Sava, Drava and Slavonia Srijem (Velić, et al., 2012). In the northernmost part of Croatia is the Mura depression, which borders Slovenia and Hungary. The Sava Depression stretches along the southwestern part of the CPB, and along the Sava River. The Drava Depression stretches along the entire length of the Drava River, bordering Hungary to the north and Serbia to the east and covers most of the CPB. The southern part of the Drava Depression borders the Medvednica and Krndija mountains. The Slavonia Srijem Depression is located east of the town of Slavonski Brod and stretches along the border with Bosnia and Herzegovina and to the border with Serbia. It is the smallest of all the depressions in the CPB (Malvić & Velić, 2011).

The geothermal potential in the CPB is associated with the pre-Neogene basement and Lower Neogene deposits and is recognised as the geothermal potential of the CPB. The pre-Neogene basement represents the main correlated unconformity in the CPB and is visible in almost all wells and seismic data (Saftić, et al., 2003) and is characterised by high temperatures in almost the entire distribution area (Cvetković, et al., 2019).

As of 2021, 13 exploration licences and 6 production licences for geothermal waters are active in Croatia. All licences are focused on the exploitation of deep geothermal energy. Since the Drava Depression is the most prolific region for geothermal energy development with geothermal gradient that varies from 0.045 to 0.065 °C/m (Macenić, et al., 2020), most of the licences are located in the Drava Depression.
Exploration activities and further plans in exploration areas goes in the direction of electricity generation and heat demand, which is especially interesting for local communities that want to include geothermal energy in their energy management system.

The main geothermal plays that are the subject of exploration activities relate to the pre-rift and sin-rift phase and represent targets potentially suitable for power generation. Exploration blocks Slatina 2, Slatina 3, Merhatovec, Legrad-1, Lunjkovec-Kutnjak, Ernestinovo, Babina Greda 1 and Babina Greda 2 are targeting pre-Neogen pre-rift play and the final aim of geothermal activities is to obtain flow and temperature sufficient for electricity production. At the same time, the post-rift clastic play arouses interest in terms of potential for heating and agricultural needs, as lower temperatures can be achieved due to the depth of the deposit and, in accordance with the characteristics of the reservoir, flows can be obtained that meet heating needs.

Korenovo, Virovitica 2, Križevci and Sveta Nedelja are aiming their activities to the post-rift play for heating purposes. Summarised data of exploration fields are presented in Table 1.

Of the 6 production fields, only the geothermal field Velika Ciglena currently produces electricity. The Velika Ciglena -1 well was commissioned in 1990 and had the task of drilling pre-Neogene reservoirs and determining the existence of hydrocarbons. During the construction of the interval 2,545.0 to 2,607.0 m, dolomite breccias were drilled and total losses occurred during the drilling (2,585.0 m), while the tests (DST-4) showed poor permeability of the reservoir. Losses during the construction of the well continued almost from a depth of 2,607.0 m to the bottom of the well at 4,790.0 m, and fragments of dolomite breccia belonging to the pre-Neogene basement were found throughout the interval. The highest temperature recorded on the thermometer was 170.0 °C, as the measuring instruments were not suitable for measuring such high temperatures. Subsequent well tests confirmed a temperature of 177.6°C at a depth of 3,593.0m. Later, three new wells were drilled - Velika Ciglena-1A, Patkovec-1 and Velika Ciglena-2, which confirmed the geothermal reservoir. Based on the reservoir parameters, the wells Velika Ciglena-1 and Velika Ciglena -1A are used as production wells, while the Patkovec -1 and Velika Ciglena-2 are injection wells. The gross installed capacity of the Velika-1 geothermal power plant is 16.5 MWe, but due to infrastructure constraints the nominal working capacity is 10.0 MWe net.

Table 1. Summarised data of geothermal exploration fields

Exploration Block	Key well final depth	Bottomhole temperatures of key wells	Geothermal gradient
	m	°C	°C/100m
Korenovo	1,457.90	67.00	3.90
Slatina 2	4,198.00	186.00	4.20
Slatina 3	4,500.00	191.00	4.10
Virovitica 2	1,600.00	70.00	3.80
Križevci	1,496.00	74.00	4.30
Ernestinovo	3,760.00	165.00	4.20
Merhatovec	4,195.00	150.00	3.40
Legrad-1	3,531.00	190.00	5.10
Lunjkovec-Kutnjak	2,430.00	144.60	5.60
Babina Greda 1	3,802.00	161.00	4.00
Babina Greda 2	3,802.00	161.00	4.00
Karlovac 1	4,145.00	139.00	3.20
Sveta Nedelja	777.00	61.40	6.60

Meanwhile, the Sveta Nedelja exploration field has received all permits and started greenhouse production, as has the Bošnjaci North field. The initial reservoir pressure of the Zagreb geothermal field is 104.0 bar at a reference reservoir depth of 979.0 m, and the initial reservoir temperature was 75.0 °C, derived from measurements at the Mladost-1 well. The Zagreb geothermal field is exploited through technological systems at three locations and is used for heating purposes. Ivanić and Bizovac fields are using geothermal energy for heating purposes while power generation on Draškovec field is underway. The geothermal gradient by field is shown in Table 2.

Table 2. Geothermal gradients of exploitation fields

Exploitation field	Geothermal gradient °C/100m
Ivanić	5.00
Bizovac	5.50
Draškovec AATG	4.40
Sveta Nedelja	5.60
Bošnjaci North	6.00
Zagreb	5.00
Velika Ciglena	4.60

The geothermal potential that is currently contracted is part of the potential that is being developed. Outside the exploration areas and the development fields, a systematic analysis of the potential has been carried out based on the data obtained from the wells.

The well data were analysed in terms of affiliation to the Drava or Sava Depression and in terms of the lithology of the deposits in relation to the three main tectonic phases during the development of the CPBS. This approach allowed a separate assessment for each of the main tectonic phases, divided into pre-rift, sin-rift and post-rift phases, in terms of specific lithological markers. Data from 181 wells were used for the analysis. The analysed well data were obtained while drilling wells for the purpose of oil and gas exploration. No inflow of hydrocarbons was achieved during the drilling of the wells, but water was recovered, so wells were abandoned after drilling. As they had no hydrocarbon potential, no extensive testing was carried out on them, but mainly short-term Drill Stem Testing. Therefore, complete data on permeability, porosity, or the amount of inflow from the reservoir in the well is not available for all wells. Thus, 75% of porosity data and 81.52% of permeability data are available from wells drilled in the Drava Depression, while in the Sava Depression porosity data are available in 74.67% of wells and permeability data in 67.42% of wells. The quality of the available data is shown in Table 3. Geothermal gradient was calculated at the depths of the reservoir with an average ambient temperature of 11.6 °C (Jelić, 1979) showing the dispersion of the geothermal gradient by lithological unit (Table 4).

Table 3. 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%

Table 4. Geothermal gradient calculated at the depths of the reservoir.

Geothermal Gradient (°C/m)	Post-Rift	Sin-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 assessment of geothermal potential in the context of modelling well data in terms of the possibility of brine inflow and in the context of Monte Carlo risk of possible permeability values at the well and determining the volume that participates in the contribution to flow in a way that allows a constant temperature at the well doublet for 30 years is estimated as heat in place of Croatian part of the Pannonian Basin. The model shows that the total volume varies from a maximum of 2094.25 PJ to a mean of 537.33 PJ to a minimum of 14.43 PJ of heat in place and includes only analysed well doublets in each lithological unit, that is, the assessment does not include the maximum available volume that can participate in the production of geothermal energy, nor creates maps of the possible potential in a given area and by lithological units. Thus, we can conclude that the mean value of heat and place per km^2 of the doublet well surface that participates in the extraction of geothermal energy for the post-rift phase ranges from 1.43 PJ/km^2 to 307.33 PJ/km^2, for the sin-rift phase from 1.29 PJ/km^2 to 1,607.75 PJ /km^2 while for the post-rift phase it is 2.67 PJ/km^2 to 985.85 PJ/km^2.

Thus, we can say that Hypothesis # 1 is proven, namely that there are possibilities for greater geothermal energy development in the Croatian part of the Pannonian Basin based on the proven geothermal gradient and the inflow from the existing wells.

Hypotheses #2 - Hydrocarbon production fields can be converted into geothermal production fields, reducing the economic constraints on the use of geothermal water for energy purposes.

In order to increase the capacity for the use of geothermal energy, it is necessary to tackle the geological assessment of the area, i.e. the land, where there is a potential for the use of geothermal energy. As hypothesis 1 proved that there is an untapped geothermal potential in Croatia outside the existing production fields, it is necessary at the same time to assess the potential of deep aquifers of oil and gas fields that are in production. Indeed, exploration and production of geothermal energy still occupies a small share of renewable energy sources both in Croatia and in Europe. One of the reasons is the geological conditions that must be in place for geothermal energy to be used, while the second reason is related to the high costs of exploration and production of geothermal energy.

The knowledge and infrastructure used for the oil industry should be utilised to increase the capacity and reduce the cost of geothermal energy production. Especially knowing that the cost of drilling and completing a geothermal well in geothermal energy production is even higher than the cost of drilling and completing oil and gas wells, due to the specificity of the geothermal well equipment, greater stability must be achieved, which also means higher capital investment (Lukawski, et al., 2014). In order to increase the use of geothermal energy, especially to reduce costs, countries that have already produced oil and gas in the past are investigating their geothermal energy potential based on abandoned oil and gas wells (Kaplanoğlu, et al., 2020). Oil fields have the potential for low to medium geothermal energy sources and have a wealth of data that should be used to reuse the fields and improve the technology for extracting geothermal energy from them (Wang, et al., 2016).

To prove hypothesis 2 in the paper, the oil field and the possibility of converting the oil field aquifer to a geothermal aquifer with existing oil production from shallower oil-saturated reservoirs was analysed. An oil field was selected that had been producing for more than 40 years and had been waterflooded during production, which led to pressure conditions almost equal to the initial values.

The objective was to analyse the possibility of producing geothermal brine from the aquifers of oil reservoirs, taking into account the constraints related to the equipment available, i.e. the diameters and depths of the well, and the conditions in the reservoir, in particular the permeability of the reservoir and the dissolved gas in the brine. In addition to reservoir parameters and equipment, the techno-economic viability was analysed in the selection of wells that can be converted from oil wells to geothermal wells, thus significantly reducing the investment in future geothermal energy production. The analysis revealed that the completion of wells is the major constraint to the economically viable production of geothermal energy. Namely, the wells are completed for oil production, i.e. all wells have production intervals covered with casing ranging from 5" to 5 ½", and production is performed through 2 7/8" tubing. Since geothermal energy production requires a higher flow rate than oil production, the tubing is ignored and production from casing is assumed.

The analysis has shown that the greatest risks in the production of brine occur when the amount of dissolved gas in the brine is assumed to be 1 m^3/m^3, while at the same time the risked permeability value of 50% is taken into account. The influence of the dissolved gas affects the flow rate and accordingly the heat transfer in the wellbore, which leads to the rejection of wells with poor permeability properties due to low flow rates. The thickness of the reservoir is a limiting factor for achieving a stable wellhead temperature and accordingly a risk factor when selecting wells for future geothermal brine production. For this reason, it is concluded that temperature stabilisation begins with reservoirs whose thickness exceeds 55 m, so that only wells whose reservoir thickness exceeds this value can be considered for future geothermal energy production.

The techno-economic analysis has shown that an energy production of 0.44 MW can be achieved at a single well, which can be achieved if the flow at the well is greater than 20 l/s and a wellhead temperature of 130°C is reached. In order to achieve sufficient energy production, a success/failure model was created as a matrix for selecting wells that achieve the minimum performance at the wellhead required for further geothermal energy production. By modelling each well it is possible to maximise energy efficiency and reduce the risk of future geothermal energy extraction. The modelling represents a conservative approach as a single well is analysed. In contrast, the cumulative effect of setting more wells in favour of geothermal energy production will have a cumulative effect on the economics of the whole model.

In order to analyse the cumulative energy effect, a numerical model of the entire field is created, where the wells are selected according to the techno-economic matrix. In this way, the effect of the wells on the production-injection parameter was analysed and an additional selection of wells was made. Since the depth of the wells and the thickness of the reservoir cannot be influenced, two scenarios were simulated in which the injection depth was varied, i.e. the perforations at the injection wells were varied so that in the first scenario the cooled brine was injected into the shallower part of the reservoir, while in the second scenario it was injected into the deeper part of the reservoir, i.e. into the deepest possible part of the reservoir, given the depth of the injection wells.

The simulation of reservoir conditions in Scenario 1 showed that the cold front intrusion covers a large part of the reservoir and the total energy in the first year is 230.011 MJ/s, while the produced energy from the reservoir drops to 221.346 MJ/s after 30 years of production. In scenario 2, the subcooling of the reservoir in the first year of production turns out to be constant, while the energy drop after the 30-year production period is smaller and amounts to 221.456 MJ/s.

The reservoir simulation model has shown that injecting cool water into the deeper part of the reservoir can lead to an increase in total field energy production. However, it shows that under Scenario 1, energy production decreases by 3.767% over the 30-year production period, while this decrease in Scenario 2 amounts 3.719% (Figure 2). The model selected 12 wells in the function of production, and the cumulative effect of the wells can be achieved by modelling in the GEOPHIRES programme the maximum power generation of 10.02 MW.

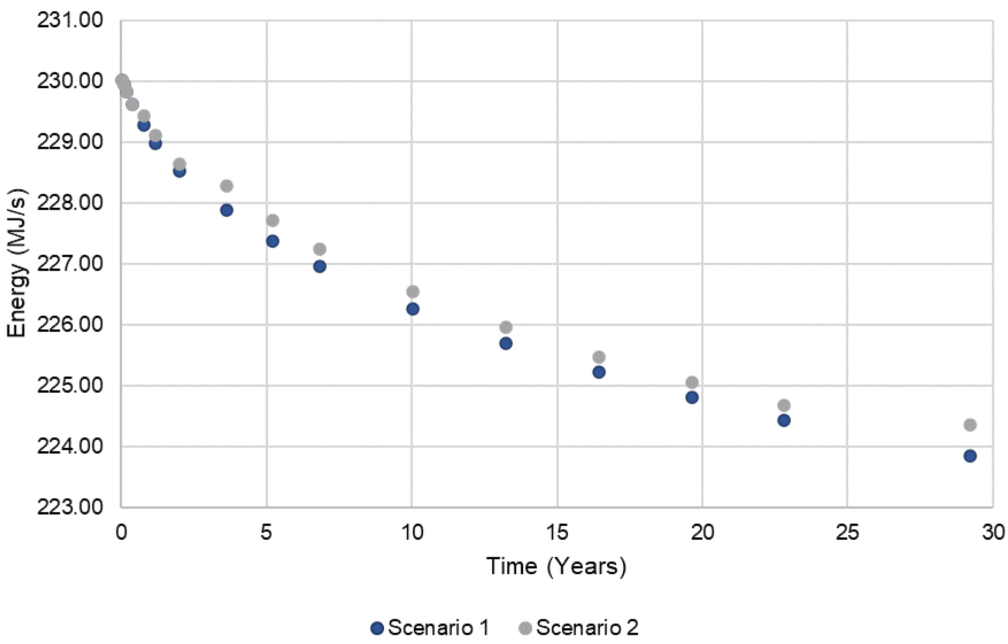


Figure 2. Numerical model simulation of geothermal energy production under two presented scenarios

The total field simulation ultimately rationalises the layout and number of wells that will participate in production.

The research results have confirmed hypothesis # 2, i.e. that deep aquifers of oil fields can be used in a technically and economically acceptable way for the extraction of geothermal energy by modelling the production parameters and selecting suitable wells for the extraction of geothermal brine.

4. CONCLUSION

An overview of activities related to the exploration and use of geothermal energy in the Republic of Croatia shows an increasing interest in the use of geothermal energy in all sectors, from electricity generation to heating and use in greenhouses. Over the years, there has been an increase in new licenced areas where exploration activities are being carried out, which, assuming positive results, will eventually lead to an increasing share of geothermal energy in the total share of renewable energy sources in Croatia. For this reason, the need for a systematic analysis and verification of the possible geothermal potential, both in terms of energy value and geographical location, has been demonstrated.

The geothermal potential of the Croatian part of the Pannonian Basin has been known for a long time, but there is no systematic analysis of its distribution. By analysing the available well data, which is a valuable source of data, a systematic analysis of the geothermal plays belonging to each lithological unit was carried out.

Modelling of heat in place with respect to the analysed doublet wells in each lithological unit showed that we can observe a total amount of maximum 2094.25 PJ to an average of 537.33 PJ to a minimum of 14.43 PJ of in-place heat, i.e. at the analysed sites.

The use of the Gringarten model allows a preliminary assessment of the area and gives us the possibility to model the reservoir in terms of the layout and number of wells that can work on the mapped geothermal reservoir. In this way, future exploration areas can be delineated where it is necessary to carry out detailed investigations, i.e. to drill additional wells that would confirm the reservoir data and increase production.

Since data from wells were used to create the model, it can be concluded that the heat in place values determined in the field support and confirm the estimates obtained. 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 the production of the well doublet.

The conversion of oil and gas field aquifers for the extraction of geothermal energy involves low and medium enthalpy geothermal energy, and therefore the analysis of favourable fields and wells must be approached in such a way as to make the best use of the available energy. By analysing the reservoir and well data of the oil field, a clear map was defined for the optimal techno-economic selection of wells favourable for the production of geothermal brine from future aquifers of oil and gas fields. When selecting a well, the use of existing infrastructure poses the greatest challenge to maximising geothermal potential, as infrastructure, especially well depth, is limited. Determining thresholds for flow parameters and temperature limits is crucial for the final selection of wells suitable for geothermal energy production and for maximising the effect of the total production of the entire field.

The scientific contribution of the dissertation is the analysis, modelling and mapping of heat in place estimation with probability distributions as the first such representation for the Croatian part of the Pannonian Basin, as well as a model of oil and gas field conversion for geothermal energy production. The contribution of the dissertation is also the definition of a workflow for the assessment of geothermal potential, both in exploration areas and in depleted oil and gas fields, and thus a contribution to the systematic assessment of future geothermal potential.

From the description of the method, it can be concluded that the geothermal potential in the Republic of Croatia is higher than estimated so further research should focus on:

- Estimate the geothermal potential covered by the total area of each lithological unit. Evaluation of the total geological volume of the geothermal potential of each lithological unit to obtain a more accurate assessment of the whole geological area, i.e. evaluation of the heat present outside the processed well data.
- Development of a further categorisation of the geothermal potential. The assessment of the heat in place provides information about the reservoir and subsequent research should focus on determining the technical and economic potential. It is necessary to analyse the potential in terms of temperature limits for the possibility of exploitation in relation to the measured temperatures and then determine an extraction factor for them, which would also show the economic potential.
- Analysis of existing oil and gas fields in terms of the possible potential of aquifers that could be used for the extraction of geothermal energy.

5. BIBLIOGRAFY

1. AAT Geothermae d.o.o., Elaborat o rezervama geotermalne vode u istražnom prostoru Draškovec AATG, Zagreb, 2016, original documentation available in Croatian Hydrocarbon Agency.
2. Agemar, T.; Weber, J.; Moeck, I.S. Assessment and Public Reporting of Geothermal Resources in Germany: Review and Outlook. Energies 2018, 11, 332. https://doi.org/10.3390/en11020332.
3. Altun, A.; Kilic, M. Thermodynamic Performance Evaluation of a Geothermal ORC Power Plant. Renewable Energy 2020, 148, 261–274. https://doi.org/10.1016/j.renene.2019.12.034.
4. Aravena, D.; Muñoz, M.; Morata, D.; Lahsen, A.; Parada, M..; Dobson, P. Assessment of High Enthalpy Geothermal Resources and Promising Areas of Chile. Geothermics 2016, 59, 1–13. https://doi.org/10.1016/j.geothermics.2015.09.001.
5. Astolfi, M.; Romano, M.C.; Bombarda, P.; Macchi, E. Binary ORC (Organic Rankine Cycles) Power Plants for the Exploitation of Medium–Low Temperature Geothermal Sources—Part A: Thermodynamic Optimization. Energy 2014, 66, 423–434. https://doi.org/10.1016/j.energy.2013.11.056.
6. Athens, N.D.; Caers, J.K. A Monte Carlo-Based Framework for Assessing the Value of Information and Development Risk in Geothermal Exploration. Appl. Energy 2019, 256, 113932. https://doi.org/10.1016/j.apenergy.2019.113932.
7. Augustine, C. Analysis of Sedimentary Geothermal Systems Using an Analytical Reservoir Model. Trans. Geotherm. Resour. Counc. 2014, 38, 641–647.
8. Augustine, C.; Tester, J.W.; Anderson, B. A Comparison of Geothermal with Oil and Gas Well Drilling Costs. In Proceedings of the Thirty-First Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, USA, 30 January–1 February 2006.
9. Barić, G. Organic Geochemistry in the Rationalization of Oil and Gas Exploration and Production. Geol. Croat. 1996, 49, 191–195. Available online: https://hrcak.srce.hr/61166 (accessed on 10 June 2023).
10. Beckers, K.F.; McCabe, K. GEOPHIRES v2.0; OSTI OAI; U.S. Department of Energy Office of Scientific and Technical Information: Washington, DC, USA, 2020. https://doi.org/10.11578/dc.20200217.1.

11. Borović, S.; Marković, I. Utilization and Tourism Valorisation of Geothermal Waters in Croatia. Renewable & Sustainable Energy Reviews 2015, 44, 52–63. https://doi.org/10.1016/j.rser.2014.12.022.
12. Bu, X.; Ma, W.; Li, H. Geothermal Energy Production Utilizing Abandoned Oil and Gas Wells. Renew. Energy 2012, 41, 80–85. https://doi.org/10.1016/j.renene.2011.10.009.
13. Caulk, R.; Tomac, I. Reuse of Abandoned Oil and Gas Wells for Geothermal Energy Production. Renew. Energy 2017, 112, 388–397. https://doi.org/10.1016/j.renene.2017.05.042.
14. Cazin, V., Jurilj, Ž., Eksploatacijsko polje geotermalne vode Zagreb i mogućnosti njezinog korištenja. 2019, Nafta i plin, https://hrcak.srce.hr/214797
15. Chen, S.-Y.; Hsieh, B.-Z.; Hsu, K.-C.; Chang, Y.-F.; Liu, J.-W.; Fan, K.-C.; Chiang, L.-W.; Han, Y.-L. Well spacing of the doublet at the Huangtsuishan geothermal site, Taiwan. Geothermics 2020, 89, 101968. https://doi.org/10.1016/j.geothermics.2020.101968.
16. Ćorić, S.; Pavelić, D.; Rögl, F.; Mandić, O.; Vrabac, S.; Avanić, R.; Jerković, L.; Vranjković, A. Revised Middle Miocene Datum for Initial Marine Flooding of North Croatian Basins (Pannonian Basin System, Central Paratethys). Geol. Croat. 2009, 62, 31–43. https://doi.org/10.4154/GC.2009.03.
17. Croatian Energy Market Operator , 2021, Available at: https://www.hrote.hr/izvjestaji, accessed 20. 9. 2021.
18. Croatian Hydrocarbon Agency, 2018, Dokumentacija za nadmetanja radi odabira najpovoljnijeg ponuditelja za istraživanje geotermalnih voda u istražnim prostorima „Slatina 1“, „Slatina 2“, „Slatina 3“ i „Slatina 4“ radi izdavanja dozvole za pridobivanje geotermalnih voda u energetske svrhe, Available at: https://www.azu.hr/media/1597/dokumentacija-za-nadmetanje-slatina_0507_hq.pdf, accessed 20. 5. 2021.
19. Croatian Hydrocarbon Agency, 2019, Dokumentacija za nadmetanje u postupku nadmetanja radi odabira najpovoljnijeg ponuditelja za istraživanje geotermalnih voda u istražnom prostoru „Križevci", Available at: https://www.azu.hr/media/1714/dokumentacija-za-nadmetanje_kri%C5%BEevci_hq.pdf, acesse 1. 6. 2021.
20. Croatian Hydrocarbon Agency, 2019. Dokumentacija za nadmetanje u postupku nadmetanja radi odabira najpovoljnijeg ponuditelja za istraživanje geotermalnih

voda u istražnom prostoru „Virovitica-2", Available at: https://www.azu.hr/media/1722/dokumentacija-za-nadmetanje_-virovitica-2__final.pdf, accessed 15. 5. 2021.

21. Croatian Hydrocarbon Agency, 2020. Bidding Round Documentation for granting a licence for the exploration of geothermal waters in the Ernestinovo exploration block, Available at: https://www.azu.hr/media/1808/dokumentacija-za-nadmetanje_ernestinovo_eng.pdf, accessed 1. 6. 2021.
22. Croatian Hydrocarbon Agency, 2020. Bidding Round Documentation for granting a licence for the exploration of geothermal waters in the Legrad-1 exploration block, Available at: https://www.azu.hr/media/1809/dokumentacija-za-nadmetanje_legrad-1_eng.pdf, Accessed 3. 6. 2021.
23. Croatian Hydrocarbon Agency, 2020. Bidding Round Documentation for granting a licence for the exploration of geothermal waters in the Lunjkovec-Kutnjak exploration block, Available at: https://www.azu.hr/media/1810/dokumentacija-za-nadmetanje_lunjkovec-kutnjak-eng.pdf, Accessed 1. 6. 2021.
24. Croatian Hydrocarbon Agency, 2020. Bidding Round Documentation for granting a licence for the exploration of geothermal waters in the Merhatovec exploration block, Available at: https://www.azu.hr/media/1807/dokumentacija-za-nadmetanje_merhatovec.pdf, Accessed 1. 6. 2021.
25. Croatian Hydrocarbon Agency, 2020. Dokumentacija za nadmetanje u postupku nadmetanja radi odabira najpovoljnijeg ponuditelja za pridobivanje geotermalnih voda u energetske srhe u istražnom porstoru "Korenovo", Available at: https://www.azu.hr/media/1857/dokumentacija-za-nadmetanje_korenovo_final_clean.pdf, accessed 15 May 2021.
26. Croatian Meteorological and Hydrological Service. 2021. Available online: https://meteo.hr/klima.php?section=klima_podaci&param=k1&Grad=osijek (accessed on 15 April 2023).
27. Cvetković, M.; Matoš, B.; Rukavina, D.; Močilac, I. K.; Saftić, B.; Baketarić, T.; Baketarić, M.; Vuić, I.; Stopar, A.; Jarić, A.; Paškov, T. Geoenergy Potential of the Croatian Part of Pannonian Basin: Insights from the Reconstruction of the Pre-Neogene Basement Unconformity. Journal of Maps 2019, 15 (2), 651–661. https://doi.org/10.1080/17445647.2019.1645052.

28. Davaux, M.; Ungemach, P.; Antics, M.; Naville, C. Geothermal derisking. How to learn and succeed from failure stories. In Proceedings of the European Geothermal Congress, Den Haag, The Netherlands, 11–14 June 2019.
29. Davis, A.; Michaelides, E.E. Geothermal Power Production from Abandoned Oil Wells. Energy 2009, 34, 866–872. https://doi.org/10.1016/j.energy.2009.03.017.
30. Dekanić, I.; Kolundžić, S.; Daria, K. Stoljeće Nafte. Veza između, nafte, novca i moći koja je promijenila svijet, 2nd ed.; Naklada Zadro: Zagreb, Croatia, 2003.
31. Dickson, M.H.; Fanelli, M. Small Geothermal Resources: A Review. Energy Sources 1994, 16, 349–376. https://doi.org/10.1080/00908319408909083.
32. DiPippo, R. Geothermal Power Plants, Principles, Applications, Case Studies and Environmental Impact. Elements of Thermodynamics; Butterworth-Heinemann: Waltham, MA, USA, 2016; pp. 715–726. https://doi.org/10.1016/b978-0-08-100879-9.00038-0.
33. DiPippo, R. Second Law Assessment of Binary Plants Generating Power from Low-Temperature Geothermal Fluids. Geothermics 2004, 33, 565–586. https://doi.org/10.1016/j.geothermics.2003.10.003.
34. Durn, T., Krpan, M. Onshore Croatia: Hydrocarbon Opportunities at the Crossroads of Europe; Geoexpo: Heggedal, Norway, 2019. Available online: https://www.geoexpro.com/articles/2019/02/onshore-croatia-hydrocarbon-opportunities-at-the-crossroads-of-europe (accessed on 1 August 2022).
35. Energetika net, 2020. Energetika net, Available at: http://www.energetika-net.com/vijesti/obnovljivi-izvori-energije/veliki-potencijali-na-geotermalnoj-busotini-blizu-stupnika-31440, accessed 5. 7. 2021.
36. Energy Development Strategy of the Republic of Croatia until 2030 with a Look at 2050. 2020. Available online: https://narodne-novine.nn.hr/clanci/sluzbeni/2020_03_25_602.html (accessed on 25 April 2023).
37. European Commision. Recovery and Resiliance Facility. 2020. Available online: https://ec.europa.eu/info/business-economy-euro/recovery-coronavirus/recovery-and-resilience-facility_en#the-recovery-and-resilience-facility (accessed on 15 August 2022).
38. European Commission. Green Plan. 2019. Available online: https://sustainabledevelopment.un.org/post2015/transformingourworld (accessed on 15 August 2022).

39. Eyerer, S.; Schifflechner, C.; Hofbauer, S.; Bauer, W.; Wieland, C.; Spliethoff, H. Combined Heat and Power from Hydrothermal Geothermal Resources in Germany: An Assessment of the Potential. Renew. Sustain. Energy Rev. 2020, 120, 109661. https://doi.org/10.1016/j.rser.2019.109661.
40. Fama, E.F.; French, K.R. The Capital Asset Pricing Model: Theory and Evidence. J. Econ. Perspect. 2004, 18, 25–46. https://doi.org/10.1257/0895330042162430.
41. Ferenc, H.; Royden, L. Mechanism for Formation of the Intra-Carpathian Basins: A Review. Earth Evol. Sci. 1981, 3, 307–316.
42. Förster, A.; Merriam, D.F.; Davis, J.C. Spatial Analysis of Temperature (BHT/DST) Data and Consequences for Heat-Flow Determination in Sedimentary Basins. Int. J. Earth Sci. 1997, 86, 252–261. https://doi.org/10.1007/s005310050138.
43. Franc-Dąbrowska, J.; Mądra-Sawicka, M.; Milewska, A. Energy Sector Risk and Cost of Capital Assessment—Companies and Investors Perspective. Energies 2021, 14, 1613. https://doi.org/10.3390/en14061613.
44. Franco, A.; Donatini, F. Methods for the estimation of the energy stored in geothermal reservoirs. J. Physics: Conf. Ser. 2017, 796, 012025. https://doi.org/10.1088/1742-6596/796/1/012025.
45. Franco, A.; Vaccaro, M. Sustainable Sizing of Geothermal Power Plants: Appropriate Potential Assessment Methods. Sustainability 2020, 12, 3844. https://doi.org/10.3390/su12093844.
46. Fridleifsson, I.B. Geothermal Energy for the Benefit of the People. Renew. Sustain. Energy Rev. 2001, 5, 299–312. https://doi.org/10.1016/s1364-0321(01)00002-8.
47. Garg, S. K.; Combs, J. G. A Reformulation of USGS Volumetric "Heat in Place" Resource Estimation Method. Geothermics 2015, 55, 150–158. https://doi.org/10.1016/j.geothermics.2015.02.004.
48. Garg, S.K.; Combs, J. Appropriate Use of USGS Volumetric Heat in Place Method and Monte Carlo Calculations. In Proceedings of the Thirty-Fourth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, USA, 1-3 February 2010. Available online: https://pangea.stanford.edu/ERE/pdf/IGAstandard/SGW/2010/garg.pdf (accessed on 1 August 2022).
49. Geoen, Elaborat o rezervama geotermalne vode eksploatacijskog polja Velika Ciglena, 2017, Zagreb, original documentation available at Croatian Hydrocarbon Agency.

50. Gharibi, S.; Mortezazadeh, E.; Bodi, S.J.H.A.; Vatani, A. Feasibility Study of Geothermal Heat Extraction from Abandoned Oil Wells Using a U-Tube Heat Exchanger. Energy 2018, 153, 554–567. https://doi.org/10.1016/j.energy.2018.04.003.

51. González-García, H.; Francke, H.; Sass, I.; Huenges, E. Production Forecast and Estimation of the Recovery Factor of the Los Humeros Geothermal Field, Mexico. Geotherm. Energy 2021, 9, 13. https://doi.org/10.1186/s40517-021-00194-z.

52. GPC Instrumentation process, Elaborat o rezerama geotermalne vode eksploatacijskog polja "Geotermalno polje Zagreb", 2018, Zagreb, original documentation available at Croatian Hydrocarbon Agency.

53. Gray, D.A.; Majorowicz, J.; Unsworth, M. Investigation of the Geothermal State of Sedimentary Basins Using Oil Industry Thermal Data: Case Study from Northern Alberta Exhibiting the Need to Systematically Remove Biased Data. J. Geophys. Eng. 2012, 9, 534–548. https://doi.org/10.1088/1742-2132/9/5/534.

54. Gringarten, A.C. Reservoir Lifetime and Heat Recovery Factor in Geothermal Aquifers Used for Urban Heating. Pure Appl. Geophys. PAGEOPH 1978, 117, 297–308. https://doi.org/10.1007/bf00879755.

55. Gringarten, A.C.; Sauty, J.P. A Theoretical Study of Heat Extraction from Aquifers with Uniform Regional Flow. J. Geophys. Res. Atmos. 1975, 80, 4956–4962. https://doi.org/10.1029/jb080i035p04956.

56. Guzović, Z.; Majcen, B.; Cvetković, S. Possibilities of Electricity Generation in the Republic of Croatia from Medium-Temperature Geothermal Sources. Applied Energy 2012, 98, 404–414. https://doi.org/10.1016/j.apenergy.2012.03.064.

57. Guzović, Z.; Rašković, P.; Blatarić, Z. The Comparision of a Basic and a Dual-Pressure ORC (Organic Rankine Cycle): Geothermal Power Plant Velika Ciglena Case Study. Energy 2014, 76, 175–186. https://doi.org/10.1016/j.energy.2014.06.005.

58. Hijriawan, M.; Pambudi, N.A.; Biddinika, M.K.; Wijayanto, D.S.; Kuncoro, I.W.; Rudiyanto, B.; Wibowo, K.M. Organic Rankine Cycle (ORC) in Geothermal Power Plants. J. Phys. 2019, 1402, 044064. https://doi.org/10.1088/1742-6596/1402/4/044064.

59. Horváth, F., Musitz, B., Balázs, A. & Végh, A., 2015, Evolution of the Pannonian Basin and Its Geothermal Resources, Geothermics, Volume 53, pp. 328-352.

60. Horváth, F.; Tari, G. IBS Pannonian Basin Project: A Review of the Main Results and Their Bearings on Hydrocarbon Exploration. Geol. Soc. London, Spéc. Publ. 1999, 156, 195–213. https://doi.org/10.1144/gsl.sp.1999.156.01.11.
61. Horvathova, J.; Mokrišova, M. Application of CAPM for the evaluation of Cost of Equity. 2014. Available online: https://exclusiveejournal.sk/files/4-2014/3-horvathova-mokrisova.pdf (accessed on 15 May 2023).
62. Hranić, J.; Raos, S.; Leoutre, E.; Rajšl, I. Two-Stage Geothermal Well Clustering for Oil-to-Water Conversion on Mature Oil Fields. Geosciences 2021, 11, 470. https://doi.org/10.3390/geosciences11110470.
63. Iglesias, E.R.; Torres, R.J. Low- to Medium-Temperature Geothermal Reserves in Mexico: A First Assessment. Geothermics 2003, 32, 711–719. https://doi.org/10.1016/j.geothermics.2003.07.002.
64. Ina, Elaborat o rezervama polja Beničanci (Reserves study of Beničanci Field)- original documentation provided by CHA, 1990, Zagreb.
65. Ina-Industrija nafte, d.d. Elaborat o rezervama ugljikovodika eksploatacijskog polja Beničanci (Reserves study of Beničanci hydrocarbon field)- original documentation provided by CHA. 2017, Zagreb.
66. INA-Industrija nafte, d.d., Elaborat o rezervama geotermalne vode eksploatacijskog polja GT Ivanić, Zagreb, 2005, original documentation available at Croatian Hydrocarbon Agency.
67. INA-Industrija nafte, d.d., Elaborat o rezervama geotermalne vode u istražnom prostoru "Drava" geotermalnog polja Velika Ciglena, Zagreb, 2007, original documentation available at Croatian Hydrocarbon Agency.
68. INA-Industrija nafte, d.d., Elaborat o rezervama geotermalne vode eksploatacijskog polja GT Ivanić, Zagreb, 2016, original documentation available at Croatian Hydrocarbon Agency.
69. INA-Industrija nafte, d.d., Elaborat o rezervama geotermalne vode eksploatacijskog polja Bizovac, stanje 31.12.2020., Zagreb, 2021, original documentation available at Croatian Hydrocarbon Agency.
70. INA-industrija nafte, Elaborat o rezervama geotermalne vode zagrebačkog geotermalnog ležišta, 1993, Zagreb, original documentation available at Croatian Hydrocarbon Agency.

71. INA-industrija nafte, Naftaplin, Elaborat o rezervama geotermalne vode - geotermalno polje Bizovac, Zagreb, 1993, original documentation available at Croatian Hydrocarbon Agency.
72. IRENA. Renewable Capacity Statistics 2023; International Renewable Energy Agency: , Abu Dhabi, 2023.
73. Jelić, K., J. Thermodynamic Characteristics of Sedimentary Complex of SW Part of Pannonian Basin (In Croatian: Termodinamičke Osobine Sedimentnog Kompleksa Jugozapadnog Dijela Panonskog Bazena). Ph.D. Thesis, University of Zagreb, Zagreb, Croatia, 1979.
74. Jelić, K.; Ćubrić, S.; Pavičić, H.; Bošnjak, R. Geothermal Energy Potential and Utilization in the Republic of. World Geothermal Congress. In Proceedings of the World Geothermal Congress 2000, Tohoku, Japan, 28 May–10 June 2000; pp. 237–246.
75. Jelić, K.; Kevrić, I.; Krasić, O. Temperatura i toplinski tok u tlu Hrvatske. In Proceedings of the 1. Hrvatski Geološki Kongres; Zagreb, Croatia, 18–21 October 1995; Vlahović, I., Velić, J., Šparica, M., Eds.; pp. 245–249.
76. Kahrobaei, S.; Fonseca, R.M.; Willems, C.J.L.; Wilschut, F.; van Wees, J.D. Regional Scale Geothermal Field Development Optimization under Geological Uncertainties. In Proceedings of the European Geothermal Conference 2019, Den Haag, The Netherlands, 11–14 June 2019.
77. Kalos, M.H.; Paula, A. Whitlock. In Monte Carlo Methods, 2nd ed.; Wiley-Blackwell: Hoboken, NJ, USA, 2008.
78. Kamila, Z.; Kaya, E.; Zarrouk, S.J. Reinjection in Geothermal Fields: An Updated Worldwide Review 2020. Geothermics 2020, 89, 101970. https://doi.org/10.1016/j.geothermics.2020.101970.
79. Kaplanoğlu, M.A.; Baba, A.; Akkurt, G.G. Use of Abandoned Oil Wells in Geothermal Systems in Turkey. Geomech. Geophys. Geo-Energy Geo-Resour. 2019, 6, 1. https://doi.org/10.1007/s40948-019-00125-0.
80. Kędzierski, P.; Nagórski, Z.; Niezgoda, T. Determination of Local Values of Heat Transfer Coefficient in Geothermal Models with Internal Functions Method. Renew. Energy 2016, 92, 506–516. https://doi.org/10.1016/j.renene.2016.02.042.
81. Kipsang, C. Cost Model for Geothermal Wells. In Proceedings of the World Geothermal Congress, Melbourne, Australia, 19–25 April 2015.

82. Kolo, I.; Sousa, R.; Zhang, T. Heat Transmission in a Geothermal Wellbore: Modelling and Application. 2014. In Proceedings of the 19th Australasian Fluid Mechanics Conference, Melbourne, Australia, 8–11 December 2014.
83. Kramers, L.; van Wees, J.-D.; Pluymaekers, M.; Kronimus, A.; Boxem, T. Direct Heat Resource Assessment and Subsurface Information Systems for Geothermal Aquifers; the Dutch Perspective. Neth. J. Geosci. 2012, 91, 637–649. https://doi.org/10.1017/s0016774600000421.
84. Kurevija, T. & Vulin, D., 2011, High enthalpy geothermal potential of deep gas fields in Central Drava Basin, Croatia, Water resources management, Vol. 25 (12), pp. 3041-3052.
85. Kurevija, T., Gregurić, M., 2008, Exergy Power Of The Binary Rankine Cycle At The Geothermal Reservoir Kutnjak-Lunjkovec. Goriva i maziva, Volume 47, pp. 20-33.
86. Kurnia, J.C.; Shatri, M.S.; Putra, Z.A.; Zaini, J.; Caesarendra, W.; Sasmito, A.P. Geothermal Energy Extraction Using Abandoned Oil and Gas Wells: Techno-Economicand Policy Review. Int. J. Energy Res. 2021, 46, 28–60. https://doi.org/10.1002/er.6386.
87. Kustra, A.; Lorenc, S. Financial Balance Analysis of Geothermal Companies in Poland Based on Managerial Cash Flows. Energies 2021, 14, 7885. https://doi.org/10.3390/en14237885.
88. Lee, K.C. Classification of Geothermal Resources by Exergy. Geothermics 2001, 30, 431–442. https://doi.org/10.1016/s0375-6505(00)00056-0.
89. Leitch, A.L.; Haley, B.; Hastings-Simon, S. Can the Oil and Gas Sector Enable Geothermal Technologies? Socio-Technical Opportunities and Complementarity Failures in Alberta, Canada. Energy Policy 2019, 125, 384–395. https://doi.org/10.1016/j.enpol.2018.10.046.
90. Lenkey, L., Dövényi, P., Horvath, F. & Cloetingh, S., 2002, Geothermics of the Pannonian basin and its bearing on the neotectonics. Stephan Mueller Special Publication Series, Volume 3.
91. Li, K.; Sun, W. Modified Method for Estimating Geothermal Resources in Oil and Gas Reservoirs. Math. Geosci. 2014, 47, 105–117. https://doi.org/10.1007/s11004-013-9516-8.

92. Li, T.; Shiozawa, S.; McClure, M.W. Thermal Breakthrough Calculations to Optimize Design of a Multiple-Stage Enhanced Geothermal System. Geothermics 2016, 64, 455–465. https://doi.org/10.1016/j.geothermics.2016.06.015.
93. Limberger, J.; Boxem, T.; Pluymaekers, M.; Bruhn, D.; Manzella, A.; Calcagno, P.; Beekman, F.; Cloetingh, S.; van Wees, J.-D. Geothermal Energy in Deep Aquifers: A Global Assessment of the Resource Base for Direct Heat Utilization. Renew. Sustain. Energy Rev. 2018, 82, 961–975. https://doi.org/10.1016/j.rser.2017.09.084.
94. Lindal, B. Industrial and other applications of geothermal energy. Geotherm. Energy, UNESCO, LC No. 7297 138, 1973, 135–148.
95. Liu, X.; Falcone, G.; Alimonti, C. A Systematic Study of Harnessing Low-Temperature Geothermal Energy from Oil and Gas Reservoirs. Energy 2018, 142, 346–355. https://doi.org/10.1016/j.energy.2017.10.058.
96. Lučić, D., Krizmanić, K., Prelogović, E., Britić, V., Mesić, I., & Tadej, J., 2001, The Neogene evolution and hydrocarbon potential of the Pannonian Basin in Croatia, Marine and petroleum Geology, 18(1), 133-147.
97. Lučić, D.; Saftić, B.; Krizmanić, K.; Prelogović, E.; Britvić, V.; Mesić, I.; Tadej, J. The Neogene Evolution and Hydrocarbon Potential of the Pannonian Basin in Croatia. Mar. Pet. Geol. 2001, 18, 133–147. https://doi.org/10.1016/s0264-8172(00)00038-6.
98. Lukawski, M.Z.; Anderson, B.J.; Augustine, C.; Capuano, L.; Beckers, K.F.; Livesay, B.; Tester, J.W. Cost Analysis of Oil, Gas, and Geothermal Well Drilling. J. Pet. Sci. Eng. 2014, 118, 1–14. https://doi.org/10.1016/j.petrol.2014.03.012.
99. Lukawski, M.Z.; Silverman, R.; Tester, J.W. Uncertainty Analysis of Geothermal Well Drilling and Completion Costs. Geothermics 2016, 64, 382–391. https://doi.org/10.1016/j.geothermics.2016.06.017.
100. Lund, J. W. & Toth, A. N., 2020. Direct utilization of geothermal energy 2020 worldwide review, Geothermics, 101915.
101. Lund, J.W.; Toth, A.N. Direct utilization of Geothermal Energy 2020 Worldwide Review. In Proceedings of the World Geothermal Congress 2020+1, Reykjavik, Iceland, 24–27 October 2021.
102. Macenić, M., Kurevija, T. & Medved, I., 2020, Novel geothermal gradient map of the Croatian part of the Pannonian Basin System based on data interpretation from

154 deep exploration wells, Renewable and Sustainable Energy Reviews, Volume 110069, p. 132.

103. Macenić, M., Kurevija, T. & Strpić, K., 2018, Systematic review of research and utilization of shallow geothermal energy in Croatia, Rudarsko Geološki Naftni Zbornik, 43(5), pp. 1-11.

104. Macenić, M.; Kurevija, T. Revitalization of Abandoned Oil and Gas Wells for a Geothermal Heat Exploitation by Means of Closed Circulation: Case Study of the Deep Dry Well Pčelić-1. Interpretation 2018, 6, SB1–SB9. https://doi.org/10.1190/int-2017-0079.1.

105. Macenić, M.; Kurevija, T.; Medved, I. Novel Geothermal Gradient map of the Croatian Part of the Pannonian Basin System Based on Data Interpretation from 154 Deep Exploration wells. Renew. Sustain. Energy Rev. 2020, 132, 110069. https://doi.org/10.1016/j.rser.2020.110069.

106. Mahmoodpour, S.; Singh, M.; Bär, K.; Sass, I. Thermo-Hydro-Mechanical Modeling of an Enhanced Geothermal System in a Fractured Reservoir Using Carbon Dioxide as Heat Transmission Fluid—A Sensitivity Investigation. Energy 2022, 254, 124266. https://doi.org/10.1016/j.energy.2022.124266.

107. Mahmoodpour, S.; Singh, M.; Mahyapour, R.; Tangirala, S.K.; Bär, K.; Sass, I. Numerical Simulation of Thermo-Hydro-Mechanical Processes at Soultz-Sous-Forêts. Energies 2022, 15, 9285. https://doi.org/10.3390/en15249285.

108. Mahmoodpour, S.; Singh, M.; Turan, A.; Bär, K.; Sass, I. Simulations and Global Sensitivity Analysis of the Thermo-Hydraulic-Mechanical Processes in a Fractured Geothermal Reservoir. Energy 2022, 247, 123511. https://doi.org/10.1016/j.energy.2022.123511.

109. Malvić, T. Kriging, Cokriging or Stochastical Simulations, and the Choice between Deterministic or Sequential Approaches. Geol. Croat. 2008, 61, 37–47. https://doi.org/10.4154/gc.2008.06.

110. Malvić, T. Regional Turbidites and Turbiditic Environments Developed during Neogene and Quaternary in Croatia. RMZ - Materials and Geoenvironment 2016, 63 (1), 39–54. https://doi.org/10.1515/rmzmag-2016-0004.

111. Malvić, T., Cvetković, M., Lithostratigraphic units in the Drava Depression (Croatian and Hungarian parts) – a correlation. Nafta [Internet]. 2013 [accesed 1.7.2021];64(1):27-33. Dostupno na: https://hrcak.srce.hr/107156

112. Malvić, T., Velić, J.; Peh, Z.; Survey, Z.C.G. Qualitative–Quantitative Analyses of the Influence of Depth and Lithological Composition on Lower Pontian Sandstone Porosity in the Central Part of Bjelovar Sag (Croatia). Geol. Croat. 2005, 58, 73–85. https://doi.org/10.4154/gc.2005.03.

113. Malvić, T.; Dinis, M. A. P.; Velić, J.; Sremac, J.; Ivšinović, J.; Bošnjak, M.; Barudžija, U.; Veinović, Ž.; Sousa, H. F. P. E. Geological Risk Calculation through Probability of Success (PoS), Applied to Radioactive Waste Disposal in Deep Wells: A Conceptual Study in the Pre-Neogene Basement in the Northern Croatia. Processes 2020, 8 (7), 755. https://doi.org/10.3390/pr8070755.

114. Malvić, T.; Velic, J. Neogene Tectonics in Croatian Part of the Pannonian Basin and Reflectance in Hydrocarbon Accumulations. In New Frontiers in Tectonic Research—At the Midst of Plate Convergence; Schattner, U., Ed.; In InTech eBooks: . https://doi.org/10.5772/21270.

115. Marković, T.; Borović, S.; Larva, O. Geochemical Characteristics of Thermal Waters of Hrvatsko Zagorje. Geologia Croatica 2015, 58 (1), 67–77. https://doi.org/10.4154/gc.2015.05.

116. Matanović, D. Cijevne alatke pri opremanju i održavanju bušotina (Tubulars in Completion and Workover Operations); Faculty of Mining, Geology and Petroleum Engineering, University of Zagreb: Zagreb, Croatia, 1999.

117. McKelvey, V.E. Mineral Resource Estimates and Public Policy. American Scientist, 60(1), 32–40. http://ui.adsabs.harvard.edu/abs/1972AmSci..60. . .32M/abstract .

118. Milora, S.L.; Tester, J.W. Geothermal Energy as a Source of Electric Power; MIT: New York, NY, USA, 1976; p. 186.

119. Ministarstvo gospodarstva i održivog razvoja, 2014, Available at: https://mingor.gov.hr/UserDocsImages/ARHIVA%20DOKUMENATA/ARHIVA %20---%20PUO/2013/11082014_rjesenje_ministarstva_od_25_srpnja_2014_godine.pdf, Accessed 10. 7. 2021.

120. Miranda, M.M.; Raymond, J.; Dezayes, C. Uncertainty and Risk Evaluation of Deep Geothermal Energy Source for Heat Production and Electricity Generation in Remote Northern Regions. Energies 2020, 13, 4221. https://doi.org/10.3390/en13164221.

121. Muffler, L.J.P. Assesment of Geothermal Resources of the United States. Geol. Surv. Circ. 1978, 790, 163.

122. Muffler, P.; Cataldi, R. Methods for regional assessment of geothermal resources. Geothermics 1978, 7, 53–89. https://doi.org/10.1016/0375-6505(78)90002-0.
123. Nadkarni, K.; Lefsrud, L.; Schiffner, D.; Banks, J. Converting Oil Wells to Geothermal Resources: Roadmaps and Roadblocks for Energy Transformation. Energy Policy 2022, 161, 112705. https://doi.org/10.1016/j.enpol.2021.112705.
124. Nádor, A.; Sebess-Zilahi, L.; Rotár-Szalkai, Á.; Gulyás, Á.; Markovic, T. New Methods of Geothermal Potential Assessment in the Pannonian Basin. Neth. J. Geosci. 2019, 98, e10. https://doi.org/10.1017/njg.2019.7.
125. Nian, Y.-L.; Cheng, W.-L. Insights into Geothermal Utilization of Abandoned Oil and Gas Wells. Renew. Sustain. Energy Rev. 2018, 87, 44–60. https://doi.org/10.1016/j.rser.2018.02.004.
126. Patterson, J.R.; Cardiff, M.; Feigl, K.L. Optimizing Geothermal Production in Fractured Rock Reservoirs under Uncertainty. Geothermics 2020, 88, 101906. https://doi.org/10.1016/j.geothermics.2020.101906.
127. Pavelić, D. Tectonostratigraphic Model for the North Croatian and North Bosnian Sector of the Miocene Pannonian Basin System. Basin Res. 2001, 13, 359–376. https://doi.org/10.1046/j.0950-091x.2001.00155.x.
128. Petroleum Experts. PROSPER User's Manual; Scantron: Eagan, MN, USA, 2013.
129. Pleić, M.; Futivić, I. 3D Seismic Interpretation of the Beničanci Oil Field. Naftaplin 2002, 19, 17–25.
130. Poulsen, S.E.; Balling, N.; Nielsen, S.B. A Parametric Study of the Thermal Recharge of Low Enthalpy Geothermal Reservoirs. Geothermics 2015, 53, 464–478. https://doi.org/10.1016/j.geothermics.2014.08.003.
131. Predovan, M.; Blecich, P. Thermodynamic analysis of a 17.5 MW geothermal power plant operating with binary Organic Rankine Cycle. Int. Sci. J. Mach. Technol. Mater. 2021, 15, 49–52. Available online: https://stumejournals.com/journals/mtm/2021/2/49 (accessed on 1 May 2023).
132. Prelogović, E.; Saftić, B.; Kuk, V.; Velić, J.; Dragas, M.; Lučić, D. Tectonic Activity in the Croatian Part of the Pannonian Basin. Tectonophysics 1998, 297 (1–4), 283–293. https://doi.org/10.1016/s0040-1951(98)00173-5.
133. Pruess, K.; Oldenburg, C.; Moridis, G. TOUGH2 Use's Guide, Version 2; Lawrence Berkeley National Laboratory: Berkeley, CA, USA, 2012.

134. Rašković, P.; Guzović, Z.; Cvetković, S. Performance Analysis of Electricity Generation by the Medium Temperature Geothermal Resources: Velika Ciglena Case Study. Energy 2013, 54, 11–31. https://doi.org/10.1016/j.energy.2013.03.009.
135. Renpu, W. Well Completion Mode Selection. In Advanced Well Completion Engineering, 3rd ed.; Elsevier: Waltham, MA, USA, 2011; pp. 75–116. https://doi.org/10.1016/b978-0-12-385868-9.00002-6.
136. Royden, L. Late Cenozoic Tectonics of the Pannonian Basin System. In AAPG Memoir 45; Royden, H.L., Horváth, F., Eds.; American Association of Petroleum Geologists: Tulsa, OK, USA, 1988; pp. 27–48.
137. Royden, L.; Horváth, F.; Rumpler, J. Evolution of the Pannonian Basin System: 1. Tectonics. Tectonics 1983, 2, 63–90. https://doi.org/10.1029/tc002i001p00063.
138. Ruris, Elaborat o rezervama geotermalne vode u istražnom prostoru "Bošnjaci-sjever", Zagreb, 2018, original documentation available at Croatian Hydrocarbon Agency
139. Rybach, L. Classification of Geothermal Resources by Potential. Geotherm. Energy Sci. 2015, 3, 13–17. https://doi.org/10.5194/gtes-3-13-2015.
140. Saftić, B.; Tomislav, M. Dubinsko kartiranje (Depth Mapping); University of Zagreb: Zagreb, Croatia, 2008.
141. Saftić, B.; Velić, J.; Sztanó, O.; Juhász, G.; Ivković, Ž. Tertiary Subsurface Facies, Source Rocks and Hydrocarbon Reservoirs in the SW Part of the Pannonian Basin (Northern Croatia and South-Western Hungary). Geologia Croatica 2003, 56 (1), 101–122. https://doi.org/10.4154/232.
142. Santos, L.; Taleghani, A.D.; Elsworth, D. Repurposing Abandoned Wells for Geothermal Energy: Current Status and Future Prospects. Renew. Energy 2022, 194, 1288–1302. https://doi.org/10.1016/j.renene.2022.05.138.
143. Schulte, D.O.; Arnold, D.; Geiger, S.; Demyanov, V.; Sass, I. Multi-Objective Optimization under Uncertainty of Geothermal Reservoirs Using Experimental Design-Based Proxy Models. Geothermics 2020, 86, 101792. https://doi.org/10.1016/j.geothermics.2019.101792.
144. Sebe, K.; Kovačić, M.; Magyar, I.; Krizmanić, K.; Špelić, M.; Bigunac, D.; Sütö-Szentai, M.; Kovács, Á.; Szuromi-Korecz, A.; Bakrač, K.; Hajek–Tadesse, V.; Troskot-Čorbić, T.; Sztanó, O. Correlation of Upper Miocene–Pliocene Lake Pannon Deposits across the Drava Basin, Croatia and Hungary. Geologia Croatica 2020, 73 (3), 177–195. https://doi.org/10.4154/gc.2020.12.

145. Shah, M.; Vaidya, D.; Sircar, A. Using Monte Carlo Simulation to Estimate Geothermal Resource in Dholera Geothermal Field, Gujarat, India. Multiscale Multidiscip. Model. Exp. Des. 2018, 1, 83–95. https://doi.org/10.1007/s41939-018-0008-x.
146. Sharpe, W.F. Capital Asset Prices: A Theory of Market Equilibrium under Conditions of Risk. J. Financ. 1964, 19, 425–442. https://doi.org/10.1111/j.1540-6261.1964.tb02865.x.
147. Shinya, T.; Yoshida, S. A Desktop Review of Calculation Equations for Geothermal Volumetric Assessment. In Proceedings of the 43rd Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, USA, 12–14 February 2018; pp. 1–18.
148. Simshauser, P. The Cost of Capital for Power Generation in Atypical Capital Market Conditions. Econ. Anal. Policy 2014, 44, 184–201. https://doi.org/10.1016/j.eap.2014.05.002.
149. Singh, M.; Mahmoodpour, S.; Ershadnia, R.; Soltanian, M.R.; Sass, I. Comparative Study on Heat Extraction from Soultz-Sous-Forêts Geothermal Field Using Supercritical Carbon Dioxide and Water as the Working Fluid. Energy 2023, 266, 126388. https://doi.org/10.1016/j.energy.2022.126388.
150. Song, J.; Loo, P.; Teo, J.; Markides, C.N. Thermo-Economic Optimization of Organic Rankine Cycle (ORC) Systems for Geothermal Power Generation: A Comparative Study of System Configurations. Front. Energy Res. 2020, 8, https://doi.org/10.3389/fenrg.2020.00006.
151. Šumanovac, F.; Orešković, J.; Grad, M. Crustal Structure at the Contact of the Dinarides and Pannonian Basin Based on 2-D Seismic and Gravity Interpretation of the Alp07 Profile in the ALP 2002 Experiment. Geophysical Journal International 2009, 179 (1), 615–633. https://doi.org/10.1111/j.1365-246x.2009.04288.x.
152. Sveinbjornsson, B.M.; Thorhallsson, S. Cost and effectiveness of geothermal drilling. In Proceedings of the SIMS 53rd Conference, Reykjavik, Iceland, 4–6 October 2012.
153. Takahashi, S.; Yoshida, S. Improvement of Calculating Formulas for Volumetric Resource Assessment. Geothermics 2016, 64, 187–195. https://doi.org/10.1016/j.geothermics.2016.04.011.

154. Tari, G.C. Alpine Tectonics of the Pannonian Basin; Rice University: Houston, TX, USA, 1994.
155. Tari, V.; Pamić, J. Geodynamic Evolution of the Northern Dinarides and the Southern Part of the Pannonian Basin. Tectonophysics 1998, 297, 269–281. https://doi.org/10.1016/s0040-1951(98)00172-3.
156. Teodoriu, C.; Falcone, G. Comparing Completion Design in Hydrocarbon and Geothermal Wells: The Need to Evaluate the Integrity of Casing Connections Subject to Thermal Stresses. Geothermics 2009, 38, 238–246. https://doi.org/10.1016/j.geothermics.2008.11.006.
157. Tuschl, M.; Kurevija, T.; Krpan, M.; Macenić, M. Overview of the current activities related to deep geothermal energy utilisation in the Republic of Croatia. Clean Technol. Environ. Policy 2022, 24, 3003–3031. https://doi.org/10.1007/s10098-022-02383-1.
158. UNFC. United Nations Framework Classification for Fossil Energy and Mineral Reserves and Resources 2009. Economic Commission for Europe, ECE Energy Series No.39., United Nations, New York and Geneva. 2010. Available online: https://unece.org/DAM/energy/se/pdfs/UNFC/unfc2009/UNFC2009_ES39_e.pdf (accessed on 1 September 2022).
159. Van Wees, J.-D.; Kronimus, A.; Van Putten, M.; Pluymaekers, M.; Mijnlieff, H. F.; Van Hooff, P.; Obdam, A.; Kramers, L. Geothermal Aquifer Performance Assessment for Direct Heat Production – Methodology and Application to Rotliegend Aquifers. Geologie En Mijnbouw 2012, 91 (4), 651–665. https://doi.org/10.1017/s0016774600000433.
160. Velić, J., Geologija ležišta nafte i plina (Geology of Oil and Gas Reservoirs); University of Zagreb: Zagreb, Croatia, 2007.
161. Velić, J., Weisser, M., Saftić, B., ; Ivković, Ž. Petreloleum-Geological Characteristics and Exploration Level of the Three Neogene Depositional Megacycles in the Croatian Part of the Pannonian Basin. NAFTA 2002, 53, 239–249.
162. Velić, J.; Malvić, T.; Cvetković, M.; Vrbanac, B. Reservoir Geology, Hydrocarbon Reserves and Production in the Croatian part of the Pannonian Basin. Geol. Croat. 2012, 65, 91–101. https://doi.org/10.4154/gc.2012.07.

163. Vrbanac, B.; Velić, J.; Malvić, T. Sedimentation of Deep-Water Turbidites in the SW Part of the Pannonian Basin. Geol. Carpathica 2010, 61, 55–69. https://doi.org/10.2478/v10096-010-0001-8.
164. Wall, A.M.; Dobson, P.F.; Thomas, H. Geothermal Costs of Capital: Relating Market Valuation to Project Risk and Technology. Geotherm. Resour. Counc. Trans. 2017, 41, 45–61.
165. Wang, K.; Liu, J.; Wu, X. Downhole Geothermal Power Generation in Oil and Gas Wells. Geothermics 2018, 76, 141–148. https://doi.org/10.1016/j.geothermics.2018.07.005.
166. Wang, K.; Yuan, B.; Ji, G.; Wu, X. A Comprehensive Review of Geothermal Energy Extraction and Utilization in Oilfields. J. Pet. Sci. Eng. 2018, 168, 465–477. https://doi.org/10.1016/j.petrol.2018.05.012.
167. Wang, S.; Yan, J.; Li, F.; Hu, J.; Li, K. Exploitation and Utilization of Oilfield Geothermal Resources in China. Energies 2016, 9, 798. https://doi.org/10.3390/en9100798.
168. Westphal, D.; Weijermars, R. Economic Appraisal and Scoping of Geothermal Energy Extraction Projects Using Depleted Hydrocarbon Wells. Energy Strategy Rev. 2018, 22, 348–364. https://doi.org/10.1016/j.esr.2018.10.008.
169. Willems, C. J. L.; Nick, H. M.; Goense, T.; Bruhn, D. The Impact of Reduction of Doublet Well Spacing on the Net Present Value and the Life Time of Fluvial Hot Sedimentary Aquifer Doublets. Geothermics 2017, 68, 54–66. https://doi.org/10.1016/j.geothermics.2017.02.008.
170. Williams, C.F.; Reed, M.J.; Robert, H.M. A Review of Methods Applied by the U.S. Geological Survey in the Assessment of Identified Geothermal Resources. In Open-File Report 2008–1296; U.S. Geological Survey, Reston, Virginia, 2008 ; 30p.
171. Zarrouk, S.J.; McLean, K. Geothermal Wells. In Geothermal Well Test Analysis; Elsevier: London, UK, 2019; pp. 39–61. https://doi.org/10.1016/b978-0-12-814946-1.00003-7.
172. Zayed, M.E.; Shboul, B.; Yin, H.; Zhao, J.; Zayed, A.A.A. Recent Advances in Geothermal Energy Reservoirs Modeling: Challenges and Potential of Thermo-Fluid Integrated Models for Reservoir Heat Extraction and Geothermal Energy Piles Design. J. Energy Storage 2023, 62, 106835. https://doi.org/10.1016/j.est.2023.106835.

173. Zhang, L.; Gao, C.; Ji, B.; Zhang, R.; Niu, J. A Simplified Assessment Method for Estimating Recoverable Geothermal Resources. Geothermics 2019, 79, 145–151. https://doi.org/10.1016/j.geothermics.2019.01.011.

174. Zhao, Z. On the Heat Transfer Coefficient between Rock Fracture Walls and Flowing Fluid. Comput. Geotech. 2014, 59, 105–111. https://doi.org/10.1016/j.compgeo.2014.03.002.

175. Živković, S., Kolbah, S., Škrlec, M. , Tumara, D., Geothermal Energy Use, Country Update for Croatia, 2019, European Geothermal Congress 2019 Den Haag, The Netherlands, 11-14 June 2019

6. BIOGRAPHY OF THE AUTHOR

Martina Tuschl was born in Zagreb in 1974. She graduated from the Faculty of Mining, Geology and Petroleum Engineering in 1998, where she was awarded the Rector's Award and received the degree of M.Sc. petroleum engineering. In 2008, she graduated from the Cotrugli Business Academy-Master of Business Administration (MBA). In 2000, she started her professional career at CROSCO, Well Integrated Services ltd. and in 2004, she started working at INA Plc. as a reservoir engineer for numerical simulations. In 2009, she became the Head of the business unit for supervision of abroad development and from 2010 to 2014, she was the Head of the Syria Projects Business Unit. In 2014, she started working at the Croatian Hydrocarbon Agency as Director of the Exploration Sector. From 2018 to 2020 she was the Director of the Exploration and Exploitation Sector and from 2021 she holds the position of Director of the Geothermal Energy Sector.