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A RESERVOIR MODEL AND PRODUCTION CAPACITY ESTIMATE FOR CAMBRIAN GEOTHERMAL RESERVOIR IN KRETINGA, LITHUANIA

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ABSTRACT

The Kretinga geothermal field in West Lithuania was treated as a model case for geothermal utilization of wells which will be abandoned after the finish of oil production. The field was chosen due to the geothermal anomaly existing in this area and because of quite favourable reservoir conditions. The Cambrian geothermal reservoir in the Kretinga oil field is briefly described with data from 7 drilled wells. Formation temperatures and initial pressures for each well are estimated and a conceptual reservoir model presented.

In this study the production potential of the deep Kretinga geothermal reservoir with reinjection was estimated. The results indicate that reinjection can increase its production by 80% from the 1997 production rates with drawdown limited to 100 m. Thermal breakthrough of the reinjection was investigated. The results show that by locating the reinjection wells at about 800 m from the production wells it will not occur within 30 years. However, those results need to be tested with a tracer test and a design is given for that. Finally a three dimensional numerical model was developed for the Kretinga geothermal reservoir, the first of its kind for a geothermal system in Lithuania.

1. INTRODUCTION

Low-temperature geothermal energy has been used cost-effectively in a number of countries where appropriate geological, hydrological and geophysical conditions are present such as in sedimentary strata. Examples of this are found in European countries like France, Poland, Hungary, Romania, Slovakia, and Serbia. In these countries geothermal water is successfully used for fish farming, in heat pump applications, horticulture for greenhouse heating, for space heating, for animal husbandry, in industry for drying products, in balneological and recreational applications such as swimming pools, health spas etc.

West Lithuania is rich in low-temperature geothermal water, both in Devonian and Cambrian sandstones.

In this area there are many possibilities for direct use of geothermal energy, particularly for space heating and health spas.

Often, in spite of favourable geological conditions, drilling costs stop geothermal developments. On the other hand, many oil fields are surrounded by hot water which might be utilized as geothermal resources. Examples of studies on this can be taken from Poland (Barbacki, 2000). This report describes the requirements to be met by oil traps for such purposes, and uses as a model case the Kretinga field, West Lithuania. The principal objectives of this study were:

- To describe conceptual model and make a numerical model of the Cambrian geothermal reservoir in the Kretinga oil field;
- To demonstrate the feasibility of using low temperature geothermal water from abandoned oil wells;
- To further develop the reservoir research project as an environmental/energy management project in Kretinga.

Simple modelling, such as lumped modelling, was used to model pressure responses due to production from the geothermal system in Kretinga. Furthermore, a coarse three-dimensional numerical model was developed for the Kretinga geothermal system. The numerical model was set up for the TOUGH2 code and can be used to simulate available information on the nature and structure of the system, downhole temperature and pressure data, as well as the response of the system to production during the last decade.

2. GEOGRAPHICAL OUTLINE OF THE STUDY AREA

Lithuania is situated in NE-Europe on the eastern coast of the Baltic Sea. Kretinga is a town (population 21,423) in West Lithuania, located close to the Baltic shore, the most popular Lithuanian resort Palanga, Klaipeda seaport and Zemaitija national park. Kretinga is the centre of a 1000 km^2 district, with 2 towns and 191 villages. In the Kretinga district, building, wood, food-processing and horticultural trades are developed. There is a well-developed infrastructure in the area surrounding the geothermal field, a railway crosses Kretinga and an asphalt roads connect it with other areas in Lithuania. The Palanga International Airport and international ferry lines are located 15-20 km from Kretinga.

The mean annual temperature is 6.7°C, the coldest month is February (-3.5°C), the hottest is July (17°C). Sometimes, severe winter frosts occur in the region. In winter, the ground freezes down to 0.8-1 m depth. There are many possibilities for geothermal utilization in the region.

The Kretinga oil field is located in the southeastern part of the town of Kretinga (Figure 1). The field covers an area of 3 km^2. This is an area of many private gardens where construction is restricted; it is sparsely populated.

The local population uses Quaternary groundwater from wells. Kretinga is supplied with artesian

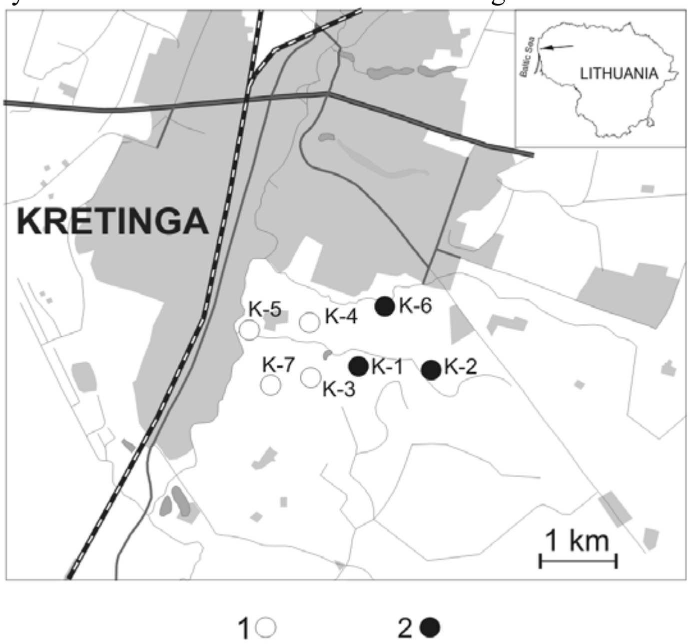

FIGURE 1: Location of wells in the Kretinga oil field; 1) Production wells; 2) Exploration wells

water from a Permian aquifer and, in some cases, some Quaternary interglacial formations.

Some artesian wells were drilled in the Kretinga area until 1967. They were shallow, and in most cases did not penetrate Quaternary deposits. The deep geological structure of the Kretinga geothermal field was first studied by seismic exploration carried out in 1968. The Kretinga wells were drilled in 1988-98. Well Kretinga-1 was drilled on the top of an expected structural dome, Kretinga-2 is 700 m further east and Kretinga-3 is 400 m to the west. The Kretinga wells are located in a flat landscape shaped by a moraine. The elevation of the wells ranges from 24.3 m (Kretinga-5) to 35.0 m (Kretinga-2). Four production wells have been drilled in the Kretinga field and three exploration wells which are closed now (Table 1). The total oil production from the field, from 1993 through 2001, is about 10 million tons. Well Kretinga-5 has produced an average of 25 1/s of fluid and well Kretinga-7, 15 1/s of fluid.

TABLE 1: Wells in the Kretinga oil field

Borehole	Drilled (year)	Depth (m)	Type
Kretinga-1	1988	2034	Exploration well
Kretinga-2	1988	2058	Exploration well
Kretinga-3	1988	2013	Production well
Kretinga-4	1989	2031	Production well
Kretinga-5	1989	1954	Production well
Kretinga-6	1990	1969	Exploration well
Kretinga-7	1998	1960	Production well

The Kretinga system has been studied extensively during the last two decades. Detailed subsurface seismic exploration has been carried out, seven wells drilled in the field and production response monitored. The numerical model made for the Kretinga geothermal system is the first model of its kind for a hydrothermal system in Lithuania. Previously developed detailed three-dimensional numerical models have been for oil systems.

3. THE KRETINGA GEOTHERMAL RESERVOIR

3.1 Available data

The oil company "Geonafta", the owner of the Kretinga oil field has provided the following data for estimation of further utilization of oil wells for geothermal purposes:

- Structural and lithological data based on geophysical exploration and laboratory analyses;
- Temperature measurements carried out in 5 boreholes;
- Hydrochemical and hydrogeological data on the Cambrian aquifer;
- Pressure and fluid production data obtained during oil field exploitation.

3.2 Geological background

The oil exploration wells in the Kretinga field were drilled within a zone characterized by a heat flow anomaly, located in the western part of Lithuania. The boreholes passed through the entire sedimentary cover and entered the Precambrian crystalline basement at a depth of 1994-2021 m (Table 2).

TABLE 2: Geological stratigraphy of the Kretinga geothermal field

Stratigraphy	Depth* (m)	Lithology
Quaternary		Morainic clays, sands
Jurassic	44.5-52	Clays, sands
Triassic	73-79	Clays, marls
Permian	199.5-206	Dolomites
Upper Devonian	233-235	Clays, dolomites, marls, sands, silts
Middle Devonian	454-480	Sands, siltstones, dolomites, marls, limestones
Lower Devonian	802-829	Differently grained sandstones, siltstones, clays, dolomitized siltstones and clays
Silurian	1032-1080	Claystones, marls, limestones
Ordovician	1685-1721	Organogenous limestones, marls
Cambrian	1814-1844	Differently grained sandstones and siltstones, claystones
Proterozoic	1943.5-1972.5	Schists, gneisses, granite-gneisses

*Depth below sea level

A wide range of observations was undertaken in the boreholes both under field conditions during their drilling, as well as after completion, and in the laboratory. The following logs were carried out in the holes: caliper, gamma-ray, neutron-neutron, spontaneous potential, resistivity, acoustic, dipmeter, temperature and others. Cores were taken from the Cambrian hydrothermal complex and the rock samples studied by different methods, such as chemical analysis of rock composition, grain size analysis and mineralogy of sedimentary rocks, analysis of cracks, chemistry of water, content of microelements in water (Stirpeika, 1992).

During drilling, stem tests were carried out to obtain data on productivity of Cambrian beds. After the hole was cased, the Cambrian hydrothermal complex was tested to estimate its planned productivity of 100 m^3/hour.

3.2.1 Lithology

Boreholes Kretinga 1 - 4 penetrated the Precambrian crystalline basement at a depth of 1943.5 m on the crest of the structure, and at 1972.5 m on the flank. The basement is composed of schists and gneisses.

Above the basement, terrigenous rocks of Cambrian age are found in the depth interval of 1814-1844 m. The Lower Cambrian sediments are composed of interlayered mudstones and siltstones . The lower part of the Cambrian section is represented by gently sloped basal sandstone composed of quartz (97.8-98.2%), mica (0.2-0.4%), and glauconite (0.4-0.6%). The Middle Cambrian deposits are mainly composed of sandy rocks (90%). The sandstones are light and light-grey, with different types of grains (fine-grained, quartziferous (99.3%), irregularly silty, micaceous (0.2-0.4%) with irregularly distributed glauconite grains (0.4-0.6%). Sandstones contain regenerated quartz cement, irregularly distributed, which causes their transition into quartzite. These sedimentary rocks are all fractured. The Cambrian deposits form the hydrothermal complex.

Ordovician deposits are found within the depth interval of 1685-1721 m. They overlie the Cambrian ones with a stratigraphic unconformity. The geologic section is composed of clayed-carbonates, represented by claystones, clayey limestones, clayey dolomites, as well as quartziferous-glauconite sandstones.

Sediments of the Silurian (1032-1080 m) are represented by a monotonous mudstone-claystone layer. Together, Ordovician and Silurian deposits form an extended regional caprock for the Cambrian hydrothermal complex with a thickness of 753-795 m.

The sediments of the lower part of the Kemeri Group are saturated with water and, together with the Pärnu regional stage of the Middle Devonian, form the Lower-Middle-Devonian hydrothermal complex. Hydrogeologic properties of this hydrogeothermal complex are much better than those in the Cambrian strata, but the temperature values are quite low 31-38°C.

3.2.2 Tectonics

From a structural point of view, the Kretinga geothermal field is located in the the Telsiai Rampart (Figure 2). The Telsiai Rampart is confined by the fault of the same name in the south. The Telsiai fault is a thrust fault. The main oil trapping mechanism in this area is a chain of anticlines along the thrust front. In the area of Kretinga, the amplitude of the thrust is about 240 m. The evolution of the Telsiai thrust was accompanied by the development of numerous faults. Such faults affect the Kretinga brachyanticline, complicating its morphology.

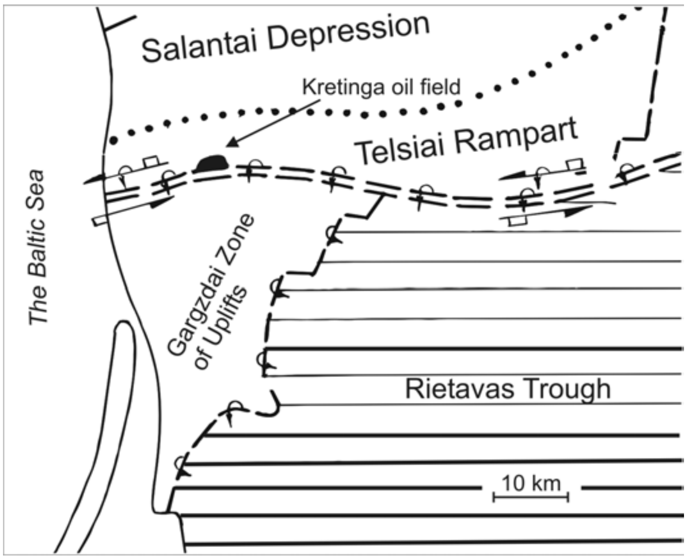

FIGURE 2: Tectonic structures in the Kretinga region; lined area marks the folded part of the basin (Stirpeika, 1999)

According to the structural map of the top of the Cambrian reservoir shown in Figure 3, the Kretinga geothermal field can be described as an elongated dome with a long axis of 3 km. The structure has a flat crest and flanks plunging 25-30 m/km to the west and east. A steeper gradient (up to 30-35 m/km) characterizes the northern flank. Due to the faulting, the southern flank is almost completely truncated by the sub-latitudinal Telsiai thrust. The slight depression to the northwest is also cut by a northeast oriented fault which divides the Kretinga and Gencai oil fields into two individual blocks. The N-S fault direction in the area of borehole Kretinga-2 is inferred from paleotectonic reconstructions.

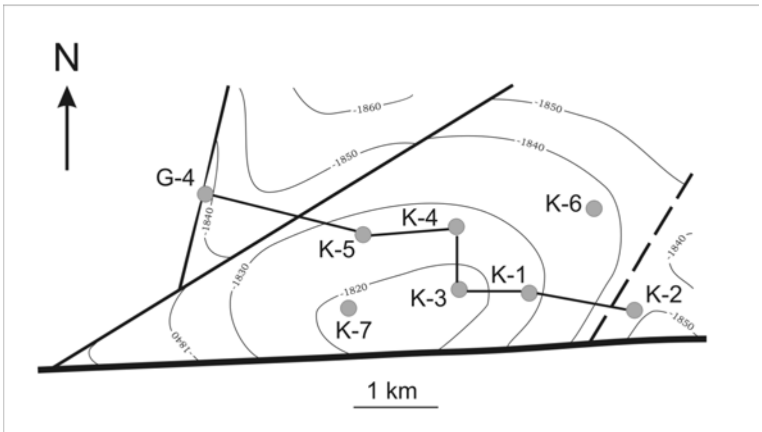

FIGURE 3: Structural map of the top of the Cambrian geothermal reservoir at Kretinga

3.3 Reservoir features

3.3.1 Initial well temperatures and pressures

Temperature logs were registered in the process of drilling and testing (Figure 4). It is well known that during the process of drilling, the natural temperature distribution along the borehole axis is distorted due to convection caused by circulating drilling mud. Usually the upper part of the section is warmed up and the lower cooled. The time elapsed since drilling finished and temperature measurements were undertaken was not enough to reach complete temperature equilibrium for the Kretinga boreholes.

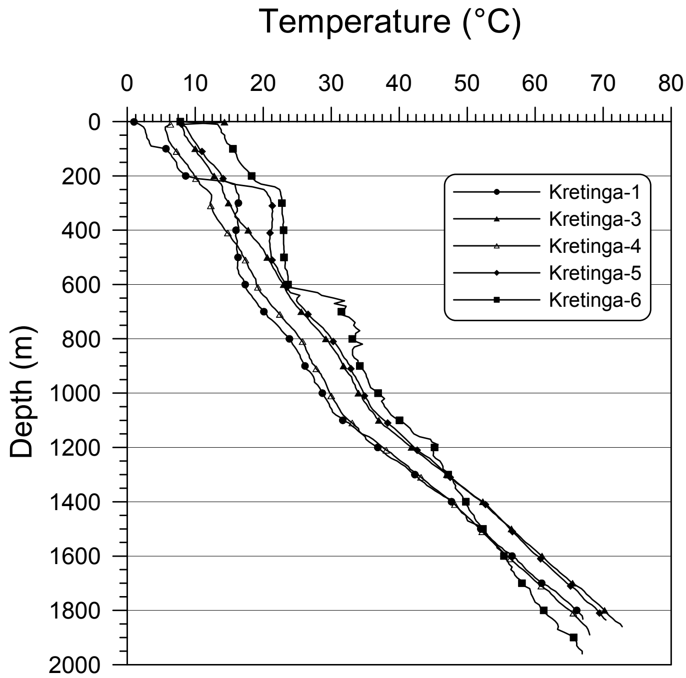

FIGURE 4: Temperature logs from the Kretinga boreholes

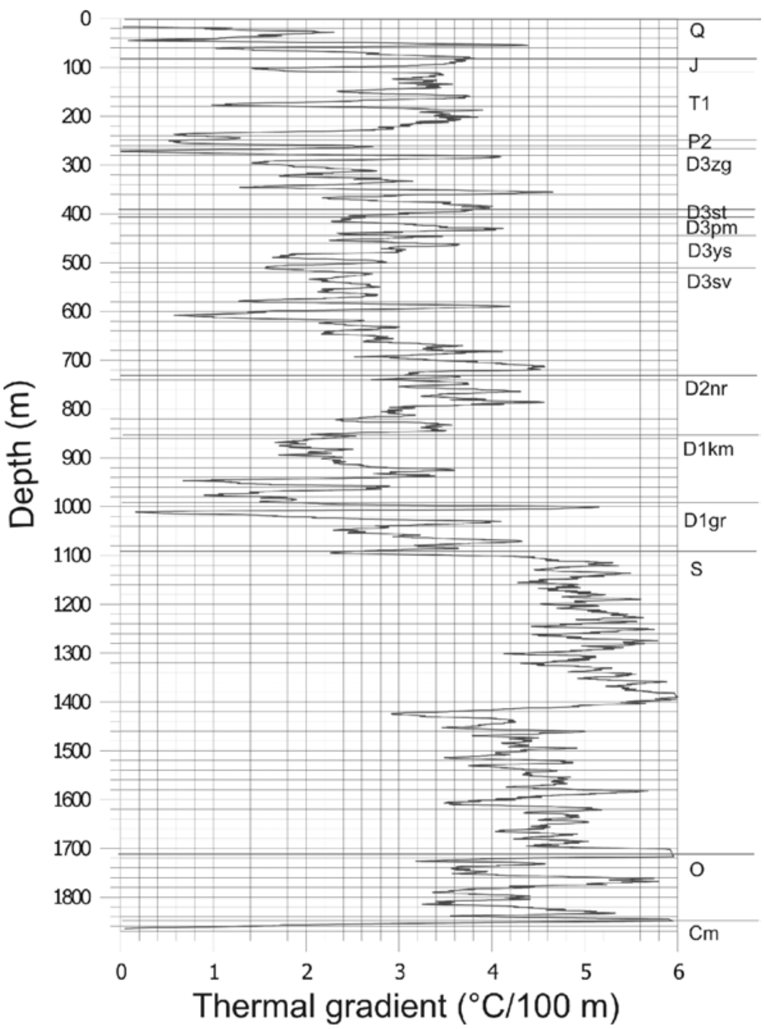

FIGURE 5: Thermal gradient curve of the Kretinga-3 well

Of the five temperature-profiles shown in Figure 4, the highest temperature values at the reservoir depths were observed within the Kretinga-3 borehole, which is closest to the centre of the Kretinga structure. The lowest values are found in Kretinga-6, drilled at the northeastern flank of the structure. The temperature decreases both eastward and northward from Kretinga-6.

The so-called "neutral layer", or the depth where annual temperature oscillations are attenuated to such a degree that they are not visible in the log, or the depth where a negative geothermal gradient (in the case of summer measurements) changes to a positive one, is at a depth around 30 m with a corresponding temperature of 13.8°C. For other boreholes, such as Gargzdai-8 and Silale-1, located in West Lithuania, this temperature is around 8.2 and 8.3°C (corresponds approximately to the annual mean ground surface temperature within this area) and observed at depths of around 20 and 30 m, respectively (Suveizdis et al., 1997). It means that the „neutral layer" had been warmed up by about 5.5°C at the time of logging. During drilling, mud circulation affected the upper part of the hole longer than the deeper part, which is not visibly distorted and probably close to the equilibrium state.

The geothermal gradient at Kretinga is affected by the heterogeneous lithology of the sedimentary cover. In vertical section, it is in the range 1-6°C/100 m. In clayey rocks, the gradient is less than in the terrigenous-carbonate section. The average value is 3.1-3.5°C/100 m, but it is higher, 5.5°C/100 m, in the Cambrian reservoir (Figure 5).

In all seven boreholes, the upper part of the geologic section is represented by loose sediments, with high permeability promoting rather intensive groundwater flow. Especially high filtration rates exist within a zone of active water exchange in the uppermost 200-250 m, where the concave form of the thermal log could be explained by the influence of prevailing atmospheric precipitation (Van Dalfsen, 1981), especially during the cold season of the year (March, April, October, November). Deeper down where permeable sands are substituted by clays, mudstones, dolomites, like in the Silurian section, the thermal log becomes less concave. The shape of thermal logs is influenced by the rocks' thermophysical properties, differing within individual layers in the upper part of the basement.

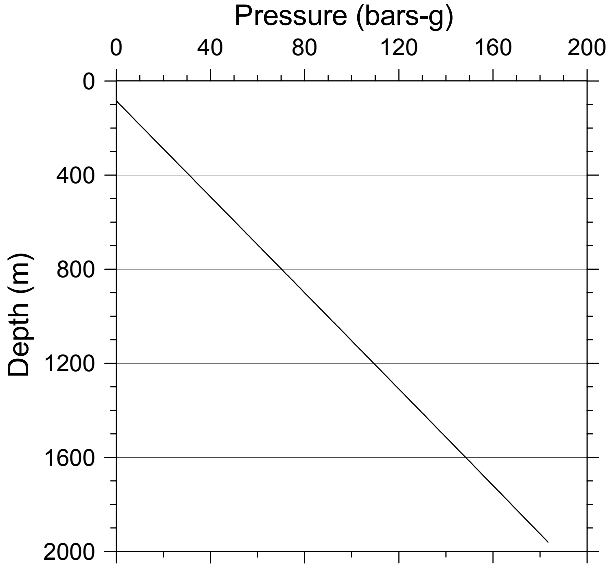

FIGURE 6: Calculated pressure log from the Kretinga-6 borehole

Since no pressure logs were available, a pressure curve for Kretinga-6 was calculated with PREDYP software (Figure 6). The calculation was made with reference to the temperature profile measured in the borehole and by assuming static water level at 84.5 m measured during well testing. According to deep manometer measurements during a well test in initial conditions, reservoir pressure was 191.9 bar at 1990 m depth, inferring that the static water level should be about 40 m higher than that used in the pressure profile calculation.

3.3.2 Hydrogeological and chemical conditions

From a hydrogeological point of view, the Kretinga geothermal field belongs to the first hydrogeological subregion of the Baltic artesian basin. A high degree of vaporisation (400-500 mm), quite considerable discharge of surface water (250-400 mm), and a minimal rate of runoff (1-3 l/s from 1 km^2) are characteristic of this subregion. Furthermore, this area is an active discharge region of the Cainozoic and Mesozoic hydrogeological stages (the Baltic Sea, the Curonian Lagoon).

There are several water-bearing complexes and horizons distinguished in the area of Kretinga oil field (Figure 7). These are sandy deposits of the Cambrian, Lower Devonian Gargzdai Group and Lower-Middle Devonian Kemeri-Parnu. Above the previous-mentioned complexes, Middle-Upper Devonian

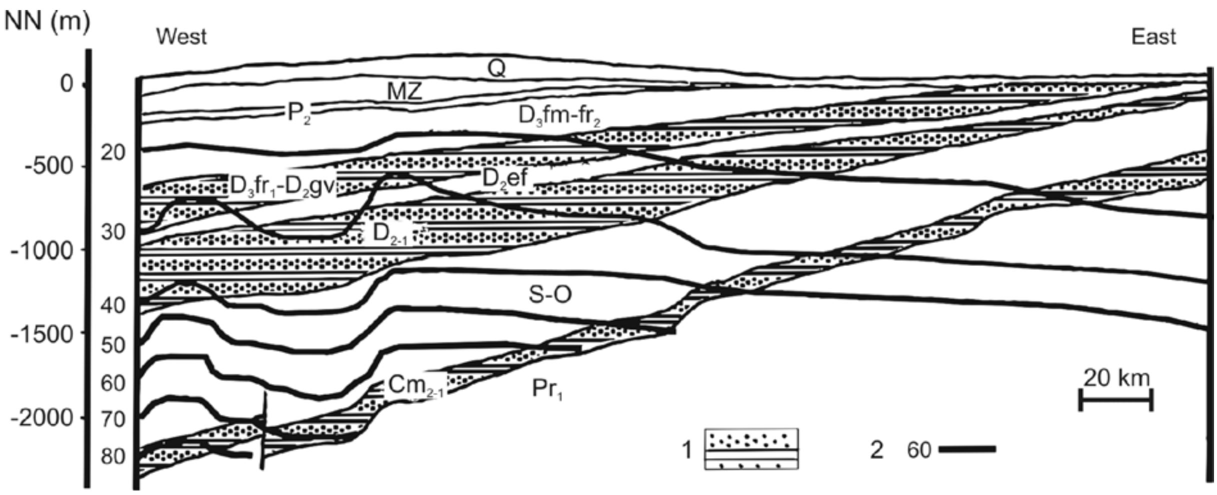

FIGURE 7: The main hydrothermal complexes of the sedimentary formations in the Kretinga region; 1) Main formations; 2) Temperature isolines (˚C)

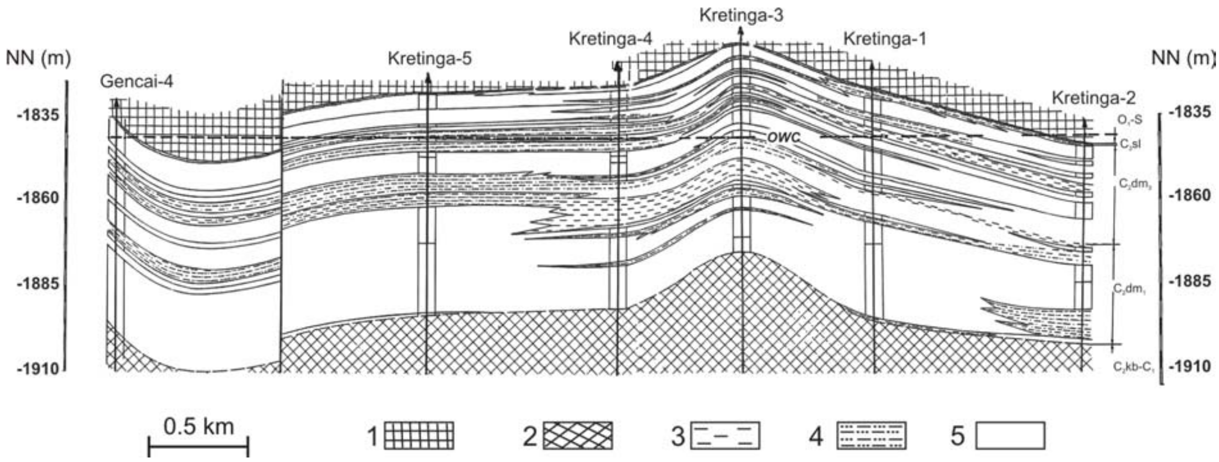

FIGURE 8: Cross-section of the Kretinga reservoir; 1) Carbonate-clayey caprock of the reservoir (O_1-S); 2) Silty-clayey aquitard (Cm_2kb-Cm_1); 3) Silty-clayey rocks (local aquitard); 4) Clayey-sandy-silty rocks (local aquitard); 5) Sandstone (aquifer)

Upninkai-Sventoji complex and Upper Devonian (Tatula-Pliavini, Istras, Stipinai, Kruoja, Akmena-Zagare), as well Permian, Jurassic and Quaternary complexes reside in the intensive groundwater migration zone. Since the Kretinga oil field is related to the Cambrian terrigenous formation (Figure 8), all hydrological explorations were carried out within it with emphasis on typical problems of fluid hydrodynamics.

The top of the Cambrian aquifer occurs at depths from 1813.6 m (Kretinga-3) to 1844 m (Kretinga-2). Its largest thickness is in the Kretinga-1 well, the smallest in Kretinga-2. This aquifer is firmly isolated from the above-lying section by up to 800 m of strata forming a cap for the aquifer. “Dryness” of the lower part of the caprock is proved by drillstem testing in the Kretinga-6 well. From a lithological point of view the Cambrian aquifer is very lithologically differentiated. It is composed of two parts; the lower one (Aisciai group) is composed of clayey-silty deposits with single reservoir rocks of sandstone; the upper part is more sandy and expressed by variably-grained sandstone with clayey siltstone interlayers of the Deimena group, which practically compounds local aquitards both vertically and laterally (Figure 8).

In the clayey Aisciai group, rare water-bearing sandy layers have only been found in the Lower Cambrian section (Cm_1gg-vr), because in the Kretinga area the Kybartai formation consists of clayey siltstone and mudstone; therefore, reservoir rocks are absent here. Characteristic of the Lower Cambrian aquifer is the low water-saturation degree, due to sporadic distribution of reservoir rocks due to high clay content of the deposits. However, in the lowermost part of the Gege formation, siltstone and sandstone have better reservoir properties and are water-saturated. This water-saturation is not uniform in the area, due to significant changes in reservoir properties in Kretinga geothermal field. This water-bearing member is determined only in two wells – Kretinga-2 and Kretinga-4. This water-bearing unit is not very thick, 2.4 and 0.8 m, respectively. Porosity of rocks ranges from 8 to 10.5%, and permeability is only 0.01-0.25×10^{-15} m^2 (0.01-0.25 mD). This layer is well isolated from the above-occurring Middle Cambrian aquifer by succession from clayey siltstone and mudstone. The Lower Cambrian aquifer is, from a hydrogeological point of view, a complicated system, where the reservoir properties and water-saturation range change both in lateral and vertical directions with intervals which are hard to determine.

The Middle Cambrian aquifer comprises Deimena formation and the Salantai unit (Cm_2dm-Cm_3sl) terrigenous rocks. In its lithological aspect, the succession is composed of quartzose, variably-grained, mostly fine-grained, sandstone and coarse-grained siltstone cemented by regenerative-quartz, more rare by clayey and dolomitic cement of contact-interstitial type with rare mudstone interlayers. This aquifer is firmly-isolated by Ordovician-Silurian caprock. The lower aquitard is a clayey Kybartai-Gege formation. The thickness of the aquifer ranges from 59.3 m (well Kretinga-2) to 71.0 m (well Kretinga-6).

The upper part of the reservoir is characterised by a fine-layered lithological differentiation of the section, with quite a wide range of changes in reservoir properties. This part of the reservoir is oil-bearing and comprises the productive part of the Kretinga oil field (except Kretinga-2 well). The lower part of the reservoir up to the oil-water contact (OWC) at 1840 m depth comprises the water-bearing part of the reservoir. In this part, the reservoir rocks comprise about 50-90% of the section with an effective thickness varying from 1 to 28.4 m. These intervals, especially in the upper part of the section, are separated from each other by compact rocks of the same lithology, more rarely by clayey pockets, of various thickness (0.5-2 m). Open porosity here ranges from 2.3 to 11.8%, and permeability from 0.02 to 283.1×10^{-15} m^2 (0.02-283 mD).

According to the well test carried out in Kretinga-6 well, a static water level was at -84.5 m (-51.1 m b.s.l.). Aquifer water has high water head. Reservoir pressure measured with a deep manometer at 1990 m depth, was 19.19 MPa (191.9 bar); transmissivity coefficient was 2.48×10^{-9} m^3/Pas; and the permeability coefficient of the reservoir 60×10^{-15} m^2 (60 mD).

Cambrian water is of chloride-calcite type, with a high content of Br^-, I^- and NH_4^+. The chemical composition of the geothermal water is shown in Table 3. This hydrochemistry is characteristic for brines with high degrees of metamorphism and closed-nature reservoirs. Gas content of the water is quite low; methane-nitrogen gases prevail with some other hydrocarbons, the contents of which vary from a few to some hundreds parts percentage, natural for water in oil fields. Helium content is unevenly distributed in the area and varies from 0.102-0.173% (wells Kretinga-3, 5, and 6) to 0.8-1.77% (wells Kretinga-1 and 2).

TABLE 3: Chemical composition of the Cambrian geothermal water in mg/l in wells of the Kretinga oil field

Borehole	Kretinga-1	Kretinga-2	Kretinga-3	Kretinga-3	Kretinga-4	Kretinga-5
Testing interval						
Top (m)	1841.9	1846.2	1793.6	1853.6	1839.4	1840
Bottom (m)	1847.4	1850.9	1890.5	1860.4	1844.8	1843.3
Density (g/cm^3)	1.105	1.113	1.051	1.1145	1.106	1.061
Salinity (meq/l)	138219.2	142476.5	65679.61	146974	134684.3	78380.41
TDS	1295.7	1360.25	569.86	1397.84	1274.23	674.2
Carbonated hardness (meq/l)		1.35	1.9	1.35	3.9	2.4
Insoluble residue	149964	151712	68520	15636	142840	86312
HCO_3^-		82	116	82	238	146
Cl^-	86807	89483	40299	92339	84406	48580
J^-	2.23	3.05	2	3.05	2.78	1.69
Br^-	692.38	711.11	608.01	759.81	696.5	459
SO_4^{2-}	61	34	529	19	83	556
B^-	18	15	3	15	10	12
Na^+	26333	26600	13268	27589	25383	15031
K^+	675	688	400	698.4	654.4	466.8
NH_4^+	9	28.8	21.6	21.6	9	25.9
Ca^{2+}	19825	21010	9050	21333	19609	11102
Mg^{2+}	3726	3792	1438	4053	3596	2070
Fe^{3+}					87.08	
Fe^{2+}	70.56	70.56	3	102.09	28.53	3.02

4. RESERVOIR MODEL

4.1 Production potential with reinjection

A simple study of water extraction and reinjection from the Cambrian reservoir has been carried out with a lumped parameter model. The other objective was to see if reservoir temperature would decline, during long-term exploitation and reinjection, assuming variable production and reinjection rates. Water was produced from the deepest and hottest part of the Cambrian layer, near the center of the syncline while 10°C water was reinjected to the same Cambrian layer some distance away from the exploitation well. Figure 9 shows the measured and simulated water level changes in well Kretinga 5.

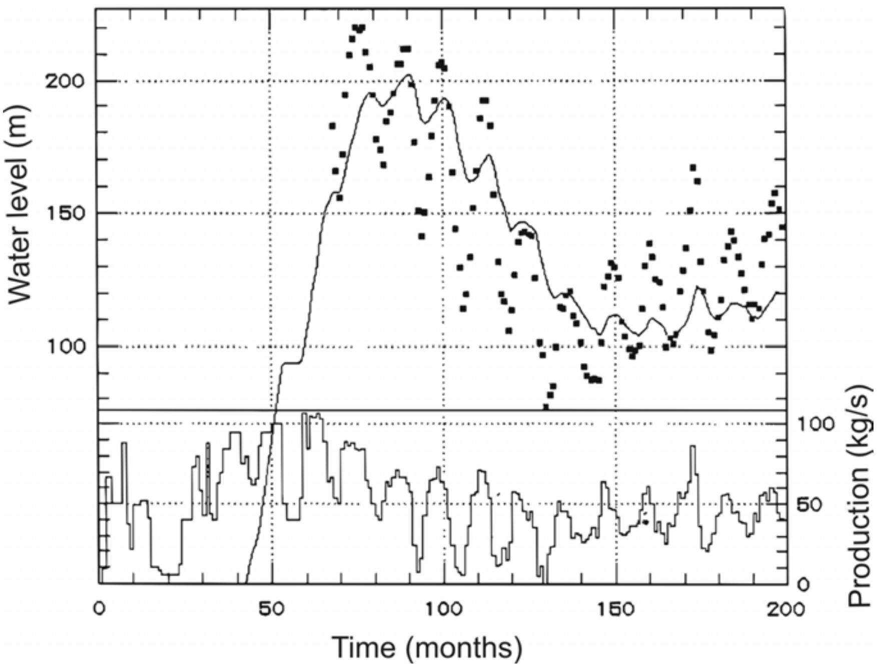

FIGURE 9: Measured and simulated water level changes in well Kretinga-5

Reinjection can provide pressure support to counteract pressure decline, and should be considered as a part of the management of the Kretinga field in the future. Reinjection is practised in numerous geothermal systems worldwide, in most cases for waste-water disposal, while in a few areas it is done to maintain reservoir pressure as suggested here (Stefánsson, 1997). In Lithuania, reinjection has been practised in the Middle-Lower Devonian porous media geothermal system in the Klaipeda geothermal field. The lumped parameter reservoir model described in this report simulates and predicts the response of the Kretinga geothermal field to production and reinjection.

All of the geothermal wells in Kretinga are cased with a 13⅜" pump pipe down to 200-300 m. At present, the pumps used in Kretinga are set at a depth of 80-100 m, depending on the production rate of each well. Therefore, allowable drawdown is here set at 100 m depth. In the more distant future the maximum allowable drawdown may be increased to 200 m depth.

For future production with an average production rate of 52 kg/s (Case 1), the dynamic water level will stay above 73 m depth for a peak production rate of 130.6 kg/s. However, for the average production rate 69 kg/s (Case 2) and the maximum production rate 183.3 kg/s during the heating period, then, according to the lumped parameter model, the dynamic water level will drop to 104 m depth in well K-6.

The Kretinga reservoir is at present clearly not overexploited. The production potential of the geothermal reservoir is estimated to be about 2.1×10^6 m^3/year, which equals an average production rate of 67 kg/s, based on the above results and an allowable drawdown of 100 m for the next five years. This is an increase of about 80% from the 1997 production rates.

4.2 Thermal breakthrough time

The main side effect anticipated from reinjection is a cooling of the reservoir and production wells. Therefore, several methods are used here to estimate the thermal breakthrough time for different injection-production well spacing, i.e. the time from initial injection until a significant cooling is observed in a production well.

First, the condition of only one reinjection well without nearby production is considered. Porous media heat transport by intergranular fluid flow is assumed. In this case the rock grains are so small that rock and fluid will have the same temperature at any point. A liquid reservoir system is assumed and the gravity affect of the variable water temperature is neglected. The differential equation, which approximately describes this process, is

$$\frac{\partial T}{\partial t} + \frac{\beta_w}{\langle \rho\beta \rangle} \bar{q}\, \nabla T = 0 \tag{1}$$

where T = Temperature (°C);
β_w = Heat capacity of water (J/kg °C);
$<\rho\beta>$ = $\phi\rho_w\beta_w + (1-\phi)\,\rho_r\beta_r$, or volumetric heat capacity of the reservoir (J/m^3 °C);
$\bar{q}$ = Mass flux vector (kg/s m^2);
∇T = $dT/dx,\ dT/dy,\ dT/dz$.

An infinite horizontal reservoir of constant thickness H, is considered. It is assumed that q kg/s of cold water ($T = 0$) are injected since time $t = 0$. The cold front consequently moves away from the well, with the radial distance from the well to the temperature front given by:

$$r_T = \left[\frac{\beta_w\, qt}{\pi H \langle \rho\beta \rangle} \right]^{\frac{1}{2}} \tag{2}$$

If we assume that the reinjected water diffuses fairly evenly through the reservoir, an average thickness of 35 m is adopted. Using q = 15 kg/s, it takes 380 years for the temperature front to move 650 m from the reinjection well. However, most of the reinjected water may travel through specific flow channels in the feed-zones. Assuming the thickness to be 3.5 m (10% of the total effective thickness), it takes the temperature front only 38 years to travel the same distance.

Another case considered is a reservoir of temperature T_0 surrounded by fluid of temperature $T = 0$, initially at a radial distance r_0. Fluid is withdrawn from a line-sink at the rate Q kg/s. In this case, the cold front reaches the well when

$$t = \frac{r_o^2\, \pi H \langle \rho\beta \rangle}{\beta_w Q} \tag{3}$$

Assuming Q = 20 kg/s and r_0 = 650 m, the coldfront reaches the production well in 150 and 15 years when the thickness is 35 and 3.5 m, respectively.

The final case considered involves production and reinjection wells with a spacing of 650 m. The average reinjection rates are assumed as 10 kg/s and 15 kg/s, and the average production rate is 30 kg/s. The thermal breakthrough is calculated by a one-dimensional flow-channel model. The program TRCOOL in the ICEBOX program package is utilised for this purpose (Arason and Björnsson, 1994). This model assumes one-dimensional flow in a flow-channel of cross-sectional area A. Given the flow channel inlet temperature T_i, the channel height h, length L and width b as well as the undisturbed rock temperature T_0, the temperature of the injected water can be estimated at any distance x along the flow channel by the equation:

$$T(x,t) = \begin{cases} T_i + (T_o - T_i)\, erf\left[\dfrac{K\,x\,h}{\beta_w q \sqrt{D(t - x/\alpha)}}\right] & t > x/\alpha \\ T_o & t \le x/\alpha \end{cases} \tag{4}$$

where α = $q\,\rho_w / <\rho\beta>\, h\, b$;
K = Thermal conductivity of the reservoir rock (W/m°C);
D = Thermal diffusivity of the reservoir rock (m^2/s);
q = Reinjection flow rate (kg/s);
and other parameters are defined as before.

When the production well produces at the rate $Q < q$, the following equation is used to calculate the production temperature T_p:

$$T_p = T_o - \frac{q}{Q}\left[T_o - T(L,t)\right] \tag{5}$$

T(L, t) is given by Equation 4.

It appears that locating reinjection wells at a distance of about 800 m from the production wells should not cause a thermal breakthrough in 20-30 years. However, these results are highly uncertain because the flow channel dimensions are unknown. A tracer test would provide very important information on this, and will be discussed later. It should also be pointed out that reinjection would only be carried out in wintertime. The reinjected water will extract more thermal energy from the rock matrix when the geothermal wells are shut down in summer, resulting in slower cooling rates than predicted.

Based on the above, it is recommended that the reinjection wells should be located at about 800 m distance from the production wells in the Kretinga geothermal field. If they are too close, reinjection may cause rapid cooling of the production wells. If they are much further away, the pressure support from reinjection will diminish.

4.3 Recommended design of a tracer test

The thermal breakthrough time estimated earlier depends on the geometry of the channels connecting the production and reinjection wells. Some assumptions have been made on this geometry. A method of detecting the flow paths and estimating the channel volume involves injection of a chemical tracer into the water, and monitoring its recovery in nearby production wells (Axelsson et al., 1995). This is a so-called tracer test. The design of such a test in Kretinga is discussed below.

One-dimensional flow, with a pore water velocity of u, is assumed in a column or a channel of porous media connecting the reinjection and production wells. Concentration is initially zero everywhere in the channel. At time $t = 0$, a mass M of the tracer is injected instantaneously into the reinjection well, and consequently transported along the flow channel to the production well. The governing equation for the concentration distribution $C(x, t)$ becomes

$$D\frac{\partial^2 C}{\partial x^2} = u\frac{\partial C}{\partial x} + \frac{\partial C}{\partial t} \tag{6}$$

The initial and boundary conditions are $C(x, 0) = 0$, and $C(x, t) = 0$ when $x \to \infty$. In addition, the total mass of the injected solute is given by

$$M = \int_{-\infty}^{\infty} \phi \, C(x,t) \, dx \tag{7}$$

The solution for the tracer concentration $C(t)$, in the produced fluid for an injection-production well-pair is given by (Axelssson et al., 1995)

$$C(t) = \frac{\mu M}{Q} \frac{1}{2\sqrt{Dt\pi}} e^{-\frac{(x-\mu t)^2}{4Dt}}, \qquad u = \frac{q}{\rho A \phi} \tag{8}$$

where x = Distance from the injection well (m);
A = Cross-sectional area of the flow channel (m^2);
q = Injection flow rate (kg/s);
Q = Production flow rate (kg/s);
D = $\alpha_L u$; or the dispersion coefficient of the flow channel (m^2/s);
α_L = Dispersivity of the channel (m).

Thus, the tracer recovery in the production well mainly depends on the geometric and hydrological properties of the formation, i.e. the cross-sectional area of the flow channel $A\phi$ and its dispersivity α_L.

A suitable tracer for the Kretinga geothermal reservoir has not been selected. Sodium-fluorescein, which can be measured at very low concentrations, has been used successfully in many geothermal fields. Whether it can be used successfully in the sandstone reservoir at Kretinga is not clear at this time. Other tracers are available. Therefore, using two tracers would be advisable.

Assume that a tracer test is conducted between wells K-7 and K-5, with a constant production of 15 kg/s from well K-5 and a stable reinjection rate into the injection well K-7. During the experiments, 10 kg of fluorescein are injected into well K-7 as a tracer. Equation 8 was used to calculate tracer recovery in well K-5 for a range of parameters. Figure 10 shows the results and can be used to estimate the amount of tracer needed in an actual tracer test as well as the sampling frequency. Since the detection limit for fluorescein is on the order of 0.1-1 ppb, 10 kg appears to be a suitable amount. If a different tracer is used, its detection limit will determine the amount needed. A sampling frequency of once per week appears to be suitable according to Figure 10, except for the first two weeks when sampling once per day is recommended.

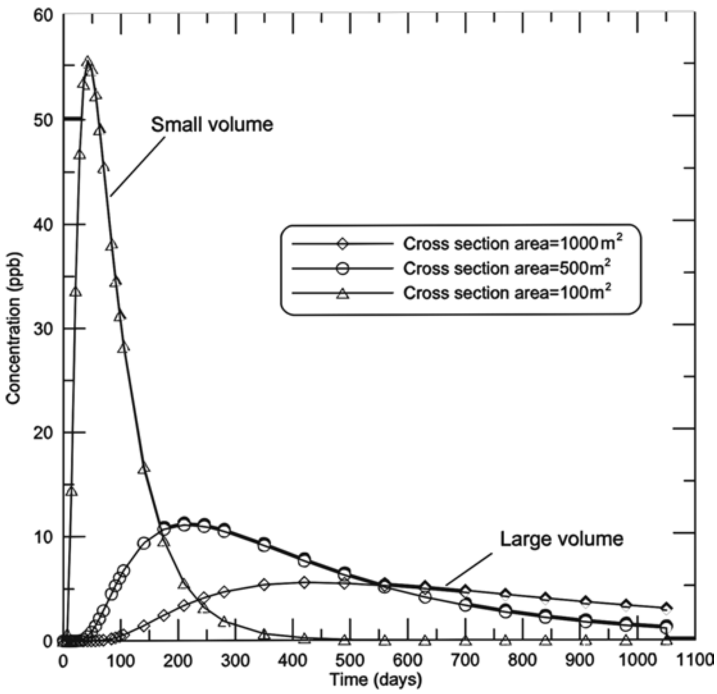

FIGURE 10: Calculated tracer recovery curves for different properties of the flow channel connecting production and reinjection wells, separated by 650 m

A tracer test lasting several months seems to be required. However, if the tracer concentration reaches the maximum value in a very short time, it means a small volume of the reservoir interacts with the injected fluid; then the tracer test may be terminated sooner than planned. On the other hand, if the injected water diffuses into a large volume, only a small part of the tracer will be recovered during the test. In that case, thermal breakthrough will not be a problem for the well doublet in question.

4.4 Conceptual model

The conceptual model is fundamental for reservoir modelling. It briefly describes the characteristics and functioning of the geothermal system. According to some geology and borehole data, the deeper geothermal system in the Kretinga oil field can be described as being a low-temperature sedimentary type reservoir, conduction-dominated and with a reservoir temperature of about 75°C. The productive aquifer is the Middle Cambrian Deimena group sandstone with an effective thickness of around 20 m. An important element in the conceptual model is a W-E striking feature, a regional fault-zone (see Chapter 3.2.2), which passes through West Lithuania including the Kretinga area (Figure 2), evident as a common feature in seismic and subsurface temperature data.

A simple sketch of the conceptual model of the Kretinga geothermal system was presented in Figure 3. The main features of the model are the following:

- Flow of water in the upper part of the system, i.e. above 1000-1500 m depth or above the production reservoir, is controlled by a fracture-zone with a W-E direction. This fracture-zone intersects younger N-S striking structures such as faults.
- The production reservoir is small in volume and the fracture-zone is confined by low-permeability rocks. In fact the production reservoir appears to be partly isolated laterally. Interference from the Kretinga area is not seen in wells located 2-3 km to the west and the east. In addition, a fault to the west of the Kretinga area probably acts as an impermeable barrier. A thick (about 740 m) caprock of the Ordovician-Silurian deposits confines the Kretinga geothermal system from above. There are no known isolated channels through the caprock linking the geothermal system with the groundwater system.
- The initial pressure and temperature distribution in the Kretinga system indicates that there could be recharge into the system from east or northeast. The temperature in the production reservoir was about 75°C (Figure 11). The entire geothermal system was over-pressurized prior to production, probably because of the caprock. It is estimated that in the natural state the pressure was as high as 195 bars at 1850 m depth, but when the first testing took place it was somewhat lower (Figure 12). On the other hand, Figure 13 shows the current reservoir pressure of the Kretinga Cambrian reservoir under exploitation.

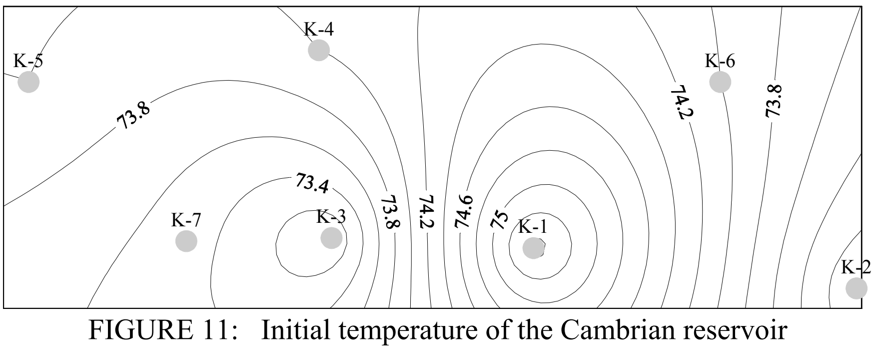

FIGURE 11: Initial temperature of the Cambrian reservoir

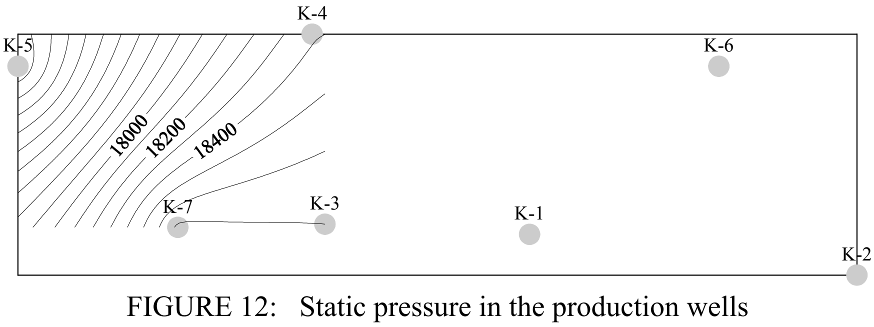

FIGURE 12: Static pressure in the production wells

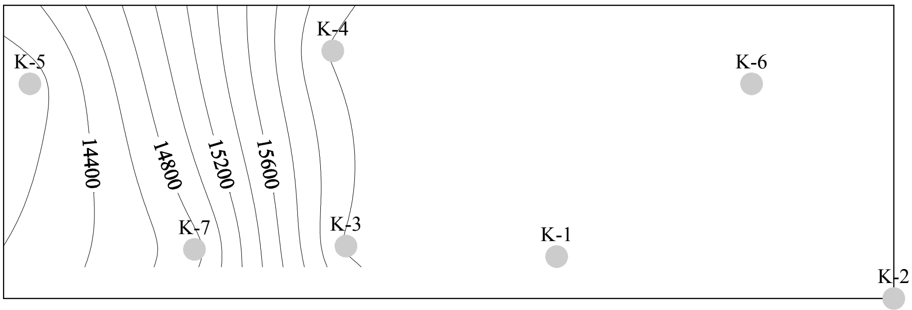

FIGURE 13: Reservoir pressure of the Cambrian reservoir under production

4.5 Numerical modelling

The numerical model of the Kretinga system is based on the conceptual model, which evolved during two decades of geothermal research in the area. The gridding of the numerical model for Kretinga is shown in Figure 14. It is composed of 5 horizontal units with a total of 250 blocks, which vary in size from 0.00025 to 1 km^3. The blocks are connected by 700 connections. Figure 14 shows a surface view of the model, which has an area of 5 km^2. The model is closed on the sides confined by faults to the south and northwest to simulate the system's apparent horizontal isolation.

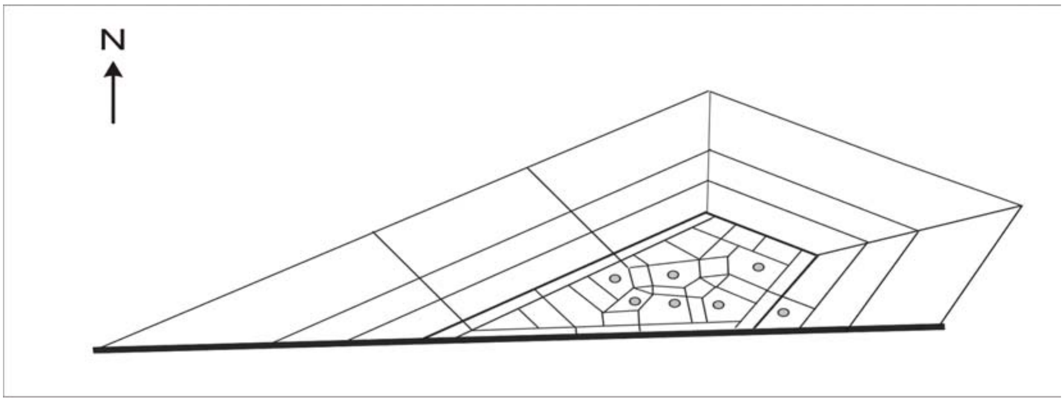

FIGURE 14: Grid for the numerical model of the Kretinga geothermal field

The main structures in the numerical model are:

1. The heat recharge system below 1900 m depth with its boundary elements, simulated by layers D and E;
2. The production reservoir, between 1800 and 1900 m depth, composed of layer C;
3. The caprock above the geothermal system (0-1800 m depth), simulated by layer B and its boundary elements (layer A).

The numerical model can be used to simulate the following:

i The natural state of the system;
ii Production history.

When a satisfactory natural state simulation has been obtained some changes may be needed to simulate the production history. That, in turn, may require a recalibration of the model for natural state simulations. Thus, several iterative cycles may be needed until a "best model", which simulates both conditions is obtained.

The numerical model was set up for the TOUGH2 simulator (Pruess et al., 1999). It can be used for three-dimensional numerical modelling of the temperature and pressure distribution of the Cambrian reservoir shown in Figures 11 and 12. The first step was to create the model grid. The grid elements in the top surface and in the base were defined as inactive boundary elements (constant pressure and temperature) with large dimensions. The grid elements are rather large, but considered sufficiently accurate for this first step of modelling the Cambrian reservoir. The model was intentionally made simple, and grid elements do not completely agree with the actual geometry of the reservoir. Besides this, some assumptions had to be made about rock properties. As an example, no distinction is made between the different kinds of rocks making up the Cambrian reservoir layer, nor in the rock groups above and below it. Also, thickness accuracy of different layers is limited.

With the model grid at hand, the next step was to simulate the natural state temperature distribution. A set of rock properties was defined for this purpose. The set is divided into 4 groups of rocks, which are presented in Table 4. These are:

1. Boundary layer;
2. Layer of horizontal sedimentary cap;
3. Cambrian reservoir; and
4. Rocks adjacent to the reservoir.

In order to obtain the measured temperature distribution, these rock properties will need to be iterated until a good match is obtained between calculated and measured temperatures.

At the end of the study period, the numerical model had only been set up and made ready for running the natural state simulations. The numerical model can be used in future continued studies of the Kretinga geothermal reservoir.

TABLE 4: Model reservoir properties; thermal conductivity is 2.5 W/m°C for all rocks, and the specific heat is 1000 J/kg; k_x - horizontal permeability, k_y - vertical permeability

Rock no.	**Rock type**	**Porosity (%)**	**k_x (m^2)**	**k_y (m^2)**	**Density (kg/m^3)**
la	Boundary layer on the top of grid	20	4×10^{-50}	0.1×10^{-15}	2400
1b	Boundary layer on the base of grid	1	4×10^{-50}	0.04×10^{-70}	2600
2	Horizontal cover	20	50×10^{-12}	0.01×10^{-15}	2400
3	Reservoir (Cambrian reservoir)	10	500×10^{-15}	50×10^{-15}	2620
4	Rock above and below reservoir	2	1×10^{-15}	0.01×10^{-15}	2600

5. SUMMARY

The Kretinga reservoir is a low-temperature sedimentary reservoir, with conduction-dominated thermal flow. The reservoir aquifer is in sandstone of Middle Cambrian age, with an average permeability of 40 mD. Its thickness is 74-113 m at depths between 1810 and 1900 m. The temperature of the geothermal fluids is 73-75°C at 1871-1900 m depth. The water is of very high salinity (brine), 78.38-146.97 g/l.

In the Kretinga oil reservoir production is from four wells at the moment. The owner of the oil field intends to use them for geothermal utilization when the oil resources are exhausted. These energy sources are characterized by the thermal energy of the reservoir water, elastic energy of compressed rocks and water and water head energy. The average free discharge from a single well is about 50 m^3/h (14 l/s). It is recommended to use a geothermal doublet in conjunction with pumping to improve this.

Considering both the positive (water level rise) and negative (cooling and possible scaling) effects, the allowable minimum distance between production and reinjection wells is determined as 800 m. Based on this, two reinjection wells were considered in the model calculation resulting in water level rise of approximately 52 m over a ten-year period. Consequently, the production potential of the Kretinga reservoir would be increased by approximately 21%. Reinjection is an essential option for reservoir management. A tracer test is suggested prior to reinjection to confirm the reservoir model.

A three-dimensional numerical model was set up for the Kretinga geothermal reservoir. The model is now ready to run using the TOUGH2-code that simulates heat and mass transfer in porous medium. This numerical model is the first of its kind for geothermal systems in Lithuania.

The main conclusions and recommendations of this report may be summarised as follows:

1. During long term utilization of the field, reinjection will allow an increase in production without causing too much drawdown. If 23% of the water produced would be reinjected into the reservoir, the calculated water level recovery reaches 17 m in five years.
2. A tracer test must be conducted in Kretinga geothermal field to detect the flow paths between injection and production wells and to estimate possible cooling resulting from injection.
3. Long-term monitoring of the Kretinga geothermal field must be further improved and equipped. The production rate, water level and water temperature for each production well need to be recorded on a regular basis, preferably continuously. In addition to being an integral part of geothermal management, it will enable more accurate modelling and more reliable predictions.

Before implementing the geothermal project, it is recommended that water samples are collected for chemical analysis to provide information on changes in the reservoir, such as cold water infiltration due to lowered reservoir pressure.

Better recognition of the Cambrian reservoir properties will enable more precise modelling in order to predict future reservoir performance. Detailed numerical simulation such as started here, can be useful for predicting changes in temperature and pressure. It can also prove useful for other aspects of reservoir engineering and environmental assessment, which have not been considered in this work.

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