Methodology for Stored Heat Evaluation That Could Be Applied In Geothermal Systems: A Case of a Mexican Field

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ABSTRACT

Geothermal wells ordinarily are exploited using the conventional methods similar to those used in oil wells in their primary production stage. However after exploitation starts the productivity decline also appears in higher or lower influence rank. The decline in productivity along exploitation is a function of the reservoir properties, mass flow rate extraction and of recharge water entrance, among other parameters. In the analyzed field it was found that the unbalance caused by the higher mass extracted in comparison with the entrance mass by recharge, is one of the reasons for productivity decline in wells. It has been observed a thermodynamic evolution of some of the wells they will achieve conditions of dry steam. In this work, a section was analyzed of a producer Mexican geothermal field, with high temperature logged, small recharge water entrance and additionally low permeability. The analyzed data show quickly the decline in productivity and in some cases lacking flow. This study is focused to rescue the completed non-producer wells some years before, which are not in use to date. Due to reservoir heterogeneity, producer wells and non producers appear as neighboring along the field. However it was possible to identify a zone, where the non-producer wells but with high temperature appear grouped. The analysis carried out allows establishing a study methodology for zones of high temperature, low permeability and low recharge water entrance, in order to evaluate the stored heat in the rock formation. The evaluation of stored heat in reservoirs that trend to decline represents a technical support for analyzing alternative methods of exploitation different to those conventionally used. The stored heat was evaluated in the analyzed zone using data of three production wells and other three non-producers. In the methodology applied, variation of values in variables was used whose determination could introduce some uncertainty degree. The variation proposed was from 0.75 to 1.25. The obtained results are expressed in MWh and show the feasibility for extending the methodology to other similar fields.

Introduction

Analysis of reservoir behavior methodologies were developed originally for characterizing and exploiting petroleum systems. From the developed technology, knowledge has been generated of exploration, drilling, exploitation and modeling reservoir which, modified to geothermal reservoirs characteristics, has shown can be applied with successful results (Blodgett and Slack, 2009). Both systems type (petroleum and geothermal) could be nested in different structural environments; however they are characterized, in general terms, by their boundaries. The reservoir has a top that works as a seal layer and a waterproof base.

The main difference between both is that while in oil systems, high pressures (400 bar) are common, in geothermal systems, temperatures vary in the order of 350 °C. The recharge due to water influx is a basic factor in both systems. According to the flow regime in the reservoir it could be possible for a uniform sweep of the fluid. In some cases appear prematurely digitations due to a displacement not uniform in the reservoir, under these conditions there is a risk for resource effective recovery. This last situation could result in an entrapment into the formation; of oil (in petroleum systems) and; of heat (in geothermal systems).

Geothermal systems, similarly to petroleum reservoirs, work during the primary production stage by their own energy, which decreases according to the formation parameters. During exploitation stage, in some cases there could be present an unbalance between the extracted mass flow and the recharge water entrance. This unbalance leads a system evolution in its thermodynamic states, which could achieve high enthalpy and their corresponding changes of fluid saturation states. Under critical conditions (low permeability, no recharge, high mass extraction, etc.,) could produce a hot dry rock system.

In this work are analyzed prevailing conditions in geothermal reservoirs with heat stored in a system of low permeability and low recharge water entrance.

Background

Different methodologies have been applied in geothermal engineering in order to improve the wells productivity and retard their decline trend. The final goal is to rescue the production of no-producer wells. The most used techniques, among others, are: Chemical stimulations which influence on the rock matrix (Katagiri *et al*., 1980), Fracturing by thermal shock (Bodvarsson and Tsang, 2012), Hydraulic fracturing (Keiiti *et al*., 2012). Under controlled conditions the thermal shock has shown successful results through opening fractures near the injection wells (Bodvarsson and Tsang, 2012). However in geothermal systems the successful of all the operations to improve productivity depends on the recharge characteristics to the reservoir.

The unbalance between the recharge and flow rate extraction produces contrasting results related with productivity decline. If the recharge water entrance is greater than produced mass flow rate, the results could be that the fluid does not extract all the heat from rock formation, resulting in a gradually decrease in production enthalpy and decline in production parameters.

In the other view point, if the recharge water entrance is too low compared with the produced mass flow the result would be a fluid evolution to a single phase (steam). The practical effects are increases in the steam quality fraction and fluid enthalpy, decreasing the mass flow rate. The critical condition of such behavior is that the producer wells will operate at their economic limit. However, in the rock formation remains the stored heat which could be extracted through others non-conventional methods. A section of a Mexican producer geothermal field was identified with these characteristics whose analysis is shown in this work.

One of the pioneer projects for heat recovery in hot dry rock systems is the developed in Fenton Hill, located to 64 km to east of Los Alamos, New México, USA (Brown, 2009). The project had considered extraction of stored heat in confined reservoirs. However, one of the main lessons from this project is the low possibility in the practice to connect two wells through the creation of a hydraulic fracture between both. It would be recommended generating a fracture using a defined well and identify their characteristics (length, direction, depth, capacity, thickness, permeability). After knowing the fracture parameters; locate and to drill a second well for intercept this and by this way achieve connection between both wells.

Previously different studies have carried out, related to heat recovery from geothermal reservoirs with low permeability and recharge (Kruger *et al*., 2000, Buttner and Huenges, 2003; Erdlac *et al*., 2007; DiPippo, 2004; Fridleifsson *et al*., 2005; Sanyal and Butler, 2009). However the geothermal reservoirs characteristics are the influence factors for taking decisions about field´s development.

Sanyal and Butler (2009) carried out a numerical simulation about feasible electric energy generation can be extracted from a unitary rock volume. The study assumes uniform reservoir rock properties including permeability and one of among others obtained results suggest an efficiency volume factor of 26 MWe/km^3. The study adds that taking into account this correlation would be necessary 0.19 km^3 of rock formation volume for generating 5 MWe.

Governing Equations

The heat conduction equation has next expression:

$$q = K_T\left(\frac{\Delta T}{z}\right) \tag{1}$$

where q (W/m^2) is the heat flow in a squared meter, ΔT (°C) is the temperature difference between two levels, z (m) is the depth and K_T (W/m °C) is the thermal conductivity of the rock.

As can be seen in Equation (1), [ΔT/z] is referred to the rock formation thermal gradient. The thermal conductivity is equivalent to heat flow per second which crosses an area of 1 m^2, under a thermal gradient of 1 (°C/m) in the flow direction.

The above equation is commonly called the volumetric method, used for geothermal reserves estimation. The advantage of this method is a quick applicability for any type of geologic resources. The parameters can be measured or estimated; however, the probable errors could be compensated at least partially (Rybach *et al*., 1981).

Thermal energy is calculated from next expression (Brook *et al*., 1978):

$$q_R = c_T A h \phi (T - T_{ref}) \tag{2}$$

where q_R (kJ) is the reservoir thermal energy, c_T (kJ/(m^3 °C) is the volumetric specific heat of the system (rock and water), in this work we used c_T = [2700 kJ/(m^3 °C)], A (m^2) is the reservoir area, h (m) is the reservoir thickness, ϕ is the porosity in the formation interval, T (°C) is the average reservoir temperature, T_{ref} (°C) is the average surface temperature.

Porosity represents vacuum spaces of the rock formation and with permeability and storage are petrophysical properties influencing the underground flow capacity (Grant et al., 1982). Because the vacuum spaces reduce the capacity of heat storage and its transfer, the porosity when entered into Equation (2) decreases the final value of the thermal energy.

The variables of Equation (2) which are related with reservoir properties provide uncertainty due to the tools accuracy used in their determinations. Brook et al., (1978) proposed the use of a values rank, between 50 and 150 % for these variables in order to calculate a general diagnosis value and establishing evaluation criteria.

Key Parameters

In each analyzed zone, the area (A), thickness (h), porosity (ϕ), thermal conductivity of rock formation (K_T) and average reservoir temperature (T) are variables that have uncertainty and, influence the stored thermal energy estimation (q_R).

Due to that this work is focused to evaluate the heat content in a reservoir volume portion, the temperature, the geometry and thermal properties of rock formation are parameters of main importance. The area value is calculated, taking as boundaries the chosen wells. As mentioned before, the area was selected taking into account the productive and thermal characteristics in producer wells and non-producers.

The thickness was determined from the depth locations of each calculated isotherm into the analyzed wells. The calculation of isotherms used the temperatures measured in wells at 24 and 30 hrs of standby. The thickness evaluation considered low and upper limits for the temperature and by applying these criteria the variation in thickness length for each well was determined.

The temperature profiles measured were used for determining the interest intervals in each well. Additionally, by lack of transient pressure test data, the determination of reservoir permeability for intervals in each well, losses fluid circulation logs during drilling, were used. These profiles were used as qualitative index of permeability and were combined with the calculated heating index using two temperature logs taken at the major resting time available in each well.

Study Area

The surface distribution and location of the wells analyzed in this studied area are shown in Figure 1. The analyzed area shows producer wells (P), and non-producers (NP). Highlights the reservoir heterogeneity due to prevailing contrasting conditions, i.e., in some cases there is a non-producer well, too close to a producer well. However it is feasible, in general terms, to take into account that non-producer wells are grouped in the eastern section of the analyzed area, as can be seen in Figure 1. For this work were analyzed six wells, three producers and three non-producers.

Temperatures higher than 200 ° C were measured at least at somewhere of their profile in the involved wells in this study. However it is important to emphasize that horizontal distribution of temperature is non-uniform.

For defining the interest interval in the well, the thickness (h) was determined considering 200 °C as upper limit. The total length of its thickness therefore will be the difference between the depth of isotherm 200 °C and total depth of each well. Although there are temperature measurements higher than 350 °C in some wells, in this work it was evaluated the profitable thickness, assuming limits between 200 and 300 °C.

Applied Analysis Methodology

According to information available, temperature logs were used at the total deep of the well, after 24 hrs of standby. We observed that measured values, at long standby times, are nearby to those calculated using the Horner static temperature method (1951). For this reason we choose data of measurements done in the analyzed wells, after about 24 - 30 hrs of standby. Figure 2 shows an example of measured temperature profiles at the total depth, losses circulation and heating index of one producer well (P1). Figure 3 is an example of temperature profiles logged at total depth, circulation lost and heating index in a non-producer well (NP3).

For each well its temperature behavior profile was analyzed which combined with other parameters, provides some qualitative idea about the formation permeability. Using temperature data measured with a difference of about 12 hrs between logs, the profiles of heating index were determined for each well. The profile of heating index of wells used as demonstrative cases is shown at right side of Figures 2 and 3. The heating index (°C/hr) reveals the heat entrance rate at the wellbore, after it has been cooled due to drilling fluid. So the peaks in the graph indicate the major quantity of heat that flows from the reservoir to the well.

The profile of fluid circulation losses during well drilling is shown at the left side of the same Figures 2 and 3. One of the main characteristics identified in this field during the wells drilling is that the field in general showed low volumes of circulation losses during drilling. The major volumes of fluid circulation losses were found at shallow depths in each well as can be seen in these two shown wells. But in all the wells studied it was found similar behavior in volumes of fluid circulation losses during drilling. It is important to emphasize that the major volumes identified at shallow depths in any case were no greater to 50 m^3/hr.

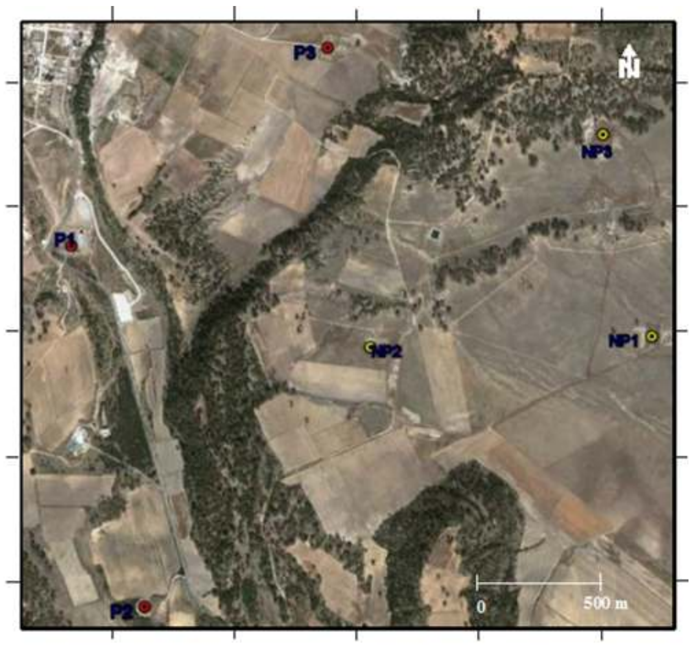

Figure 1. Location of the analyzed wells in the studied field.

The fluid circulation losses measured at deep zones of the well were small, *i.e.* the variation never was more than 20 m^3/hr. Even in some cases were found greater volumes of fluid circulation losses in non-producer wells than in producers. However, it can be assumed that this behavior be related to the existence of low permeability at well depth. An important observation is that the measured low volumes of fluid circulation losses are related with its heating index increase as can be seen in Figures 2 and 3.

From the analysis carried out in all the involved wells, we can observe in some of them, a clear increase in the calculated values of heating index. This behavior generally occurs in producer wells. Through comparison profiles behavior of heating index in a producer well (P1) with another non-producer well (NP3), it is possible to identify the difference in behavior of both types. It is important to emphasize that it was identified a good difference in heating index values in producer wells, although the low volumes of their circulation losses. However, it is possible to identify changes, in lesser ranges, in the increase of heating index in non-producers wells. Minor changes were observed in the heating index profile of these wells as can be seen in Figure 3. This condition could be explained taking into account that the drilling fluid cools the rock formation,

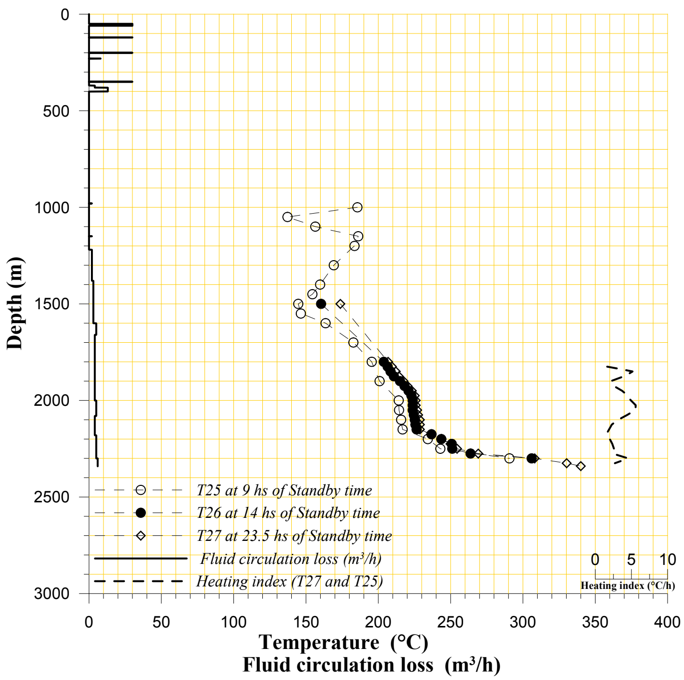

Figure 2. Temperature logs at different standby times and fluid circulation losses during drilling in well P1.

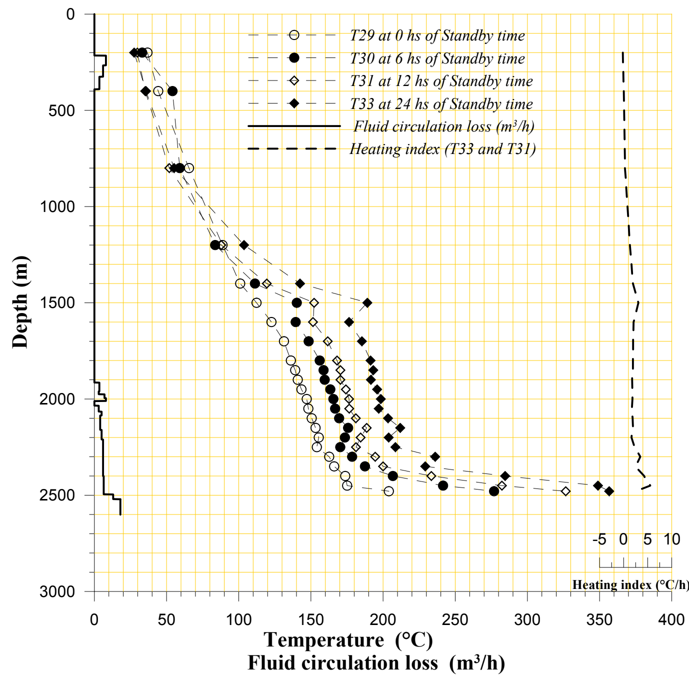

Figure 3. Temperature logs at different standby time and fluid circulation losses during drilling in well NP3.

but after standby time and by lack of water entrance, the heat again returns to rock.

Through combination of temperature profiles with the heating index, the thickness interval interest for each well were defined, assuming the useful limits between 200 °C and 300 °C. Table 1 shows location of the depths in the wells for each isotherm, as indicative of thicknesses of interest in the analyzed wells.

Table 1. Depth of temperature locations along the analyzed wells for isotherms of 200, 250 and 300 °C.

Well	Total Depth (m)	Temperature Location (Depth)		
		T = 200 °C	T = 250 °C	T = 300 °C
*P_1	2340	1460	1643	1826
*P_2	2440	1550	1750	2022
*P_3	2292	1308	1386	1496
*NP_1	2621	2504	2522	2545
*NP_2	2546	1621	1925	2351
*NP_3	2600	1444	1626	2025

*The producer wells are called with P, while non-producer wells with NP.

The isotherms for 200, 250 and 300 °C were calculated using temperature measured data of each analyzed well. A cross section E-W developed using these calculated isotherms, is shown in Figure 4. This figure gives an idea about temperature distribution along this field section.

The reservoir heterogeneity was the reason for identifying three different thicknesses in the studied zone. Using the depths of the calculated isotherms in each well, thickness lengths were determined for 200, 250 and 300 °C. The feasible thickness lengths that can be exploited from heat stored are shown in Table 2.

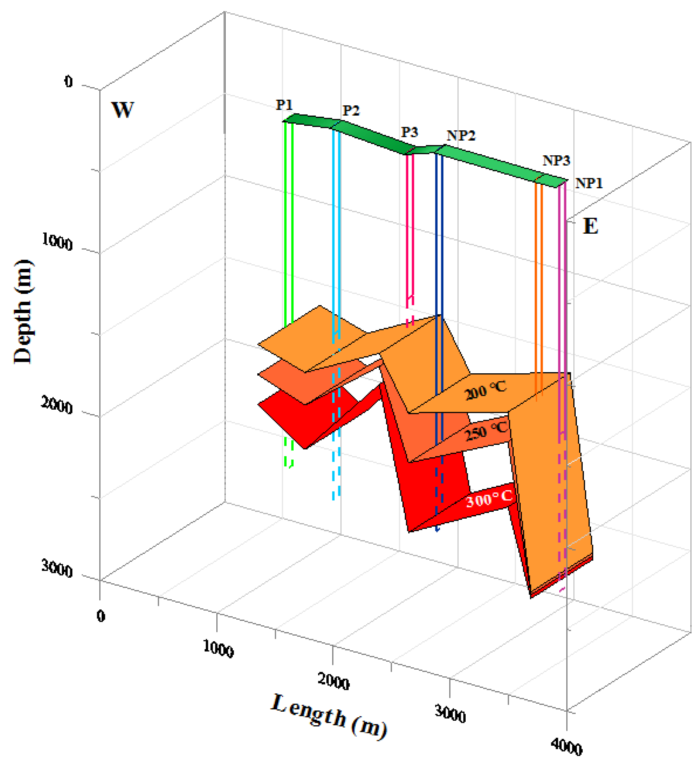

Figure 4. Temperature distribution along the section of the analyzed wells involved, within the study area.

From Figure 4 it can be seen the isotherms distribution for producer wells which occur at higher levels than those determined for the non-producers wells. In addition, from a geographical view point, the producer wells are grouped at the west section of the analyzed area, leaving the eastern section, for grouping of the non-producer wells.

The behavior analysis of each one of the thermal and petrophysical characteristics of these two wells P1 and NP3, was applied to all the wells involved in this study area. Although in this work only examples for two of all the involved wells are shown. According to the temperature profiles correlated with fluid circulation losses and heating index, the interest thickness in each well by its heat storage was determined.

By using the values of the depths of each isotherm and the total depth drilled in the well, the useful thickness was calculated, for heat extraction.

Table 2. Thicknesses resulting from temperature locations for 200, 250 and 300 °C in each of the analyzed wells.

Well	Thickness (m)		
	T = 200 °C	T = 250 °C	T = 300 °C
*P_1	880	697	514
*P_2	890	690	418
*P_3	984	906	796
*NP_1	117	99	76
*NP_2	925	621	195
*NP_3	1156	974	575

Due to shown evidences about temperatures existence, up to 200 °C in some wells of this section, was carried out the analysis in order to rescue these drilled wells. In order to determine the volume feasible for heat storage the analyzed total area was calculated. The boundaries of this area were assumed to the east by the non-producer wells NP1 and NP3, and to west, the bound is marked by the half-length between the non-producers wells, and its nearby producer. So, we assumed the half of the distance between the NP2 and P1 wells, and the NP3 and P2 wells. The estimated area according to last assumptions resulted in a value of 1219947 m^2 as can be seen in Figure 5.

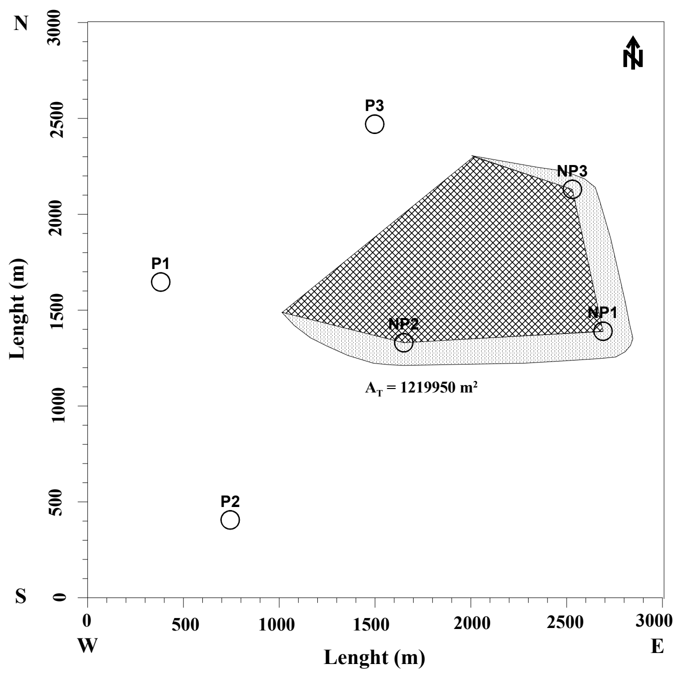

Figure 5. Example of area with heat storage, feasible to be exploited using alternative methodologies different to conventional techniques.

For obtaining the thicknesses values for isotherms of 200, 250 and 300 °C there were determined mean values of nearby wells. So according to Figure 5, the mean thicknesses were calculated using values of wells pairs, as follows: NP2 with P1; NP3 with P2; NP1 with NP2 and NP1 with NP3.

The heat stored in the rock volume bounded by the involved wells in this study was determined using Equation (2). The specific heat (c_T) was used as 2700 [kJ/(m^3 °C)], for porosity (ϕ) was used a mean value of 15 % and the surface annual temperature (T_{ref}) was assumed as 20 °C. Determinations for different reservoir temperatures were carried out for values of 200, 250 and 350 °C.

Taking into account that $3.6(10)^6$ Joules are equivalent to 1 kWh, the conversion factor was applied for obtaining the equivalent MWh in the analyzed area. Table 3 shows the results obtained for the heat stored in the analyzed rock volume, for cases of temperatures reservoir of 200, 250 and 300 °C. Also were applied the criteria proposed by Brook *et al.*, (1978), only they were modified for variables with uncertainty, using values rank of 0.75 and 1.25, in place of 0.5 and 1.5, for the low and high limits respectively.

Table 3. Determined values of heat stored in the rock volume, bounded by wells involved in the analyzed area.

Uncertainty	MWh			
	T = 200 °C	T = 200 °C	T = 250 °C	T = 300 °C
Low limit	4.68E+13	12.9956	12.8591	8.7092
Normal	6.24E+13	17.3275	17.1455	11.6122
High limit	7.80E+12	21.6594	21.4319	14.5153

The total area could be expanded if the drainage radii (r_e), of each well are known, under this view point in Figure 5, this addition can be seen. The outer fringe to the study area of Figure 5, corresponds to the drainage radii of the analyzed wells. This area is approximately 300000 m^2, which is equivalent to 25 % of the total considered area in this study. Taking into account the criteria proposed by Brook *et al.*, (1978), the obtained results as "Low" and "High" limits shown in Table 3, are inside the values rank. As mentioned before in this analysis we used a more reduced values rank.

Discussion Results

Due to reservoir heterogeneity in this geothermal field it is common to find production conditions nearby to non-producer wells. For this reason we carefully choose the wells for analyzing in the study area, considering their grouping and location outside the production zone. Through this fact the behavior of isotherms distribution could be explained, as shown in cross section of Figure 4. The lines of the isotherms cross the production wells at lesser depths that in those non-producer wells.

The analyzed zone is characterized by wells with low permeability and high temperatures at deep conditions. Due that in this paper we take advantage of the existing wells that are not in use in a field, it is important to considering their mechanical completions. Under last view point and because the study is focused to the heat extraction, we considered useful thicknesses those limited by temperatures of 200 °C and the total depth of each well. Naturally the length between the depth for the 200 °C isotherm and the total depth of each well is greater than the length between the isotherm of 300 °C and its total depth. The calculated volumes are influenced by the mean values of thicknesses for each well. The calculation of stored heat is a function of the temperature, the thickness, porosity and the area of the analyzed zone, for this reason in Table 3 can be illustrated these differences.

Considering that some variables introduce an uncertainty grade due to methods for their measurement and in this case mainly to the reservoir heterogeneity we applied the criteria proposed by Brook *et al*., (1978) using particular modifications. Mainly were carried out determinations of heat stored, considering values variation into the rank of 0.75 and 1.25. The rock volumes calculated using the thicknesses length between 200 °C and total depth, are higher than those calculated for 300 °C and the total depth. These differences in values of stored heat converted to MWh can be distinguished in Table 3.

The use of Equation (2) implies reservoir variables which involve some uncertainty even in homogenous systems. The uncertainty increases in heterogeneous systems such as the analyzed case. For calculating the stored heat all the variables intervening have an uncertainty grade; the area, the thickness, porosity, reservoir temperature. By this reason it is highly recommended to apply the criteria of Brook *et al*., (1978).

Conclusions

The main conclusions of this study are as follows:

It was reviewed that geothermal reservoirs normally are exploited using the conventional methods similar to those used in petroleum fields in their primary production stage.

The decline in productivity with exploitation is a function of the reservoir properties and of recharge water entrance. The unbalance caused by the higher mass extracted in comparison with the entrance mass by recharge, is one of the reasons of thermodynamic evolution of the reservoir, to achieving the conditions of dry steam.

In this work it was analyzed a section of a producer Mexican geothermal field, with logged high temperature, low recharge water entrance, and additionally low permeability.

Due to reservoir heterogeneity, producer wells and non-producers would appear as neighboring along the field. Despite this heterogeneity it was possible to identify a zone, bringing together only the non-producer wells but with high temperature.

The analysis carried out allows establishing a study methodology for zones of high temperature, low permeability and low recharge entrance water, in order to evaluate the stored heat in the rock formation.

The evaluation of stored heat in reservoirs with a high tendency to decline represents a technical support for analyzing alternative methods of exploitation different to those conventionally used.

The stored heat was evaluated in the analyzed zone using data of three production wells and other three non-producers. In the methodology applied, variation of values in variables was used to determine the introduction of uncertainty degree. The variation proposed was from 0.75 to 1.25. The results obtained are expressed in MWh and show the feasibility for extending the methodology to other similar fields.

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