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WELL DATA ANALYSIS AND VOLUMETRIC ASSESSMENT OF THE SOL DE MAÑANA GEOTHERMAL FIELD, BOLIVIA

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ABSTRACT

Bolivia is located in South America, where the subduction of the Nazca Plate under the South American Plate generates the Andes volcanic chain that crosses Bolivia. In 1976, ENDE and the Ministry of Energy and Hydrocarbons, with funds from the United Nations Development Programme (UNDP), began evaluating the geothermal potential of 42 hydrothermal manifestations, and the Laguna Colorada area was considered the most prospective. Geo-volcanological mapping indicates the existence of an extensive ignimbrite unit that almost completely covers the area, and overlies an andesitic-dacitic lava sequence and possibly ignimbrites of Neogene origin. The structural geology shows two orthogonal tectonic systems, NNW-SSE and NNE-SSW, and this structural system has caused secondary deep fracturing that allows hot water to rise up through faults and fractures to reach the surface in hydrothermal alteration zones. The temperature obtained from geothermometers are in agreement with the measured reservoir temperature of around 250°C. Geophysical studies carried out in the exploration stage identified important gravimetric and resistive anomalies. When correlated with MT data, this information allows the identification of the possible reservoir extension.

Six wells were drilled between 1989 and 1994 in the Sol de Mañana geothermal field, confirming high temperature (250-260°C). Temperature cross-section allows better understanding of the reservoir characteristics. Results of well testing show similar characteristics for wells SM-01 and SM-02 and better connection between these two wells than other wells in the field. These results correlated with the structural geology, indicate that wells SM-01 and SM-02 could intersect the same fault. Based on temperature measurements and well test analysis, an initial resource assessment is done using the volumetric method considering two scenarios. The most likely value obtained for the production capacity of the Sol de Mañana geothermal field, is 75 MW_e for 25 years.

1. INTRODUCTION

1.1 Location and project history

Bolivia is located in South America and covers 1,980,581 km^2, it is bordered by Chile and Peru in the west, by Brazil in the east and north and by Argentina and Paraguay in the south. The subduction of the

Nazca Plate under the South American Plate generates the Andes volcanic chain and the Andes crosses Bolivia with two branches: Cordillera Occidental and Cordillera Oriental, the Altiplano plateau is located between these branches.

The Bolivian National Electricity Company (ENDE) and the Bolivian Geological Survey (GEOBOL) started the geothermal development in Bolivia in 1970s in the Cordillera Occidental by studying 42 geothermal manifestations and concluding that there is significant potential in this region.

In 1976, ENDE and the Ministry of Energy and Hydrocarbons, with funds from the United Nations Development Programme (UNDP) based on the study by GEOBOL (GEOBOL, 1976), began evaluating the geothermal potential in; Volcan Sajama, Valle de rio Empexa, Salar de Laguna, Volcan Ollague-Cachi, Laguna Colorada, Laguna Verde and Quetena, Three of the seven fields were considered the most prospective: Laguna Colorada, Sajama and Valle de rio Empexa located along the Occidental Cordillera (GEOBOL, 1976). Figure 1 shows the Laguna Colorada area and the location of the geothermal field. Laguna Colorada is the name of the area where ENDE has its geothermal project, but Sol de Mañana is the name of geothermal field.

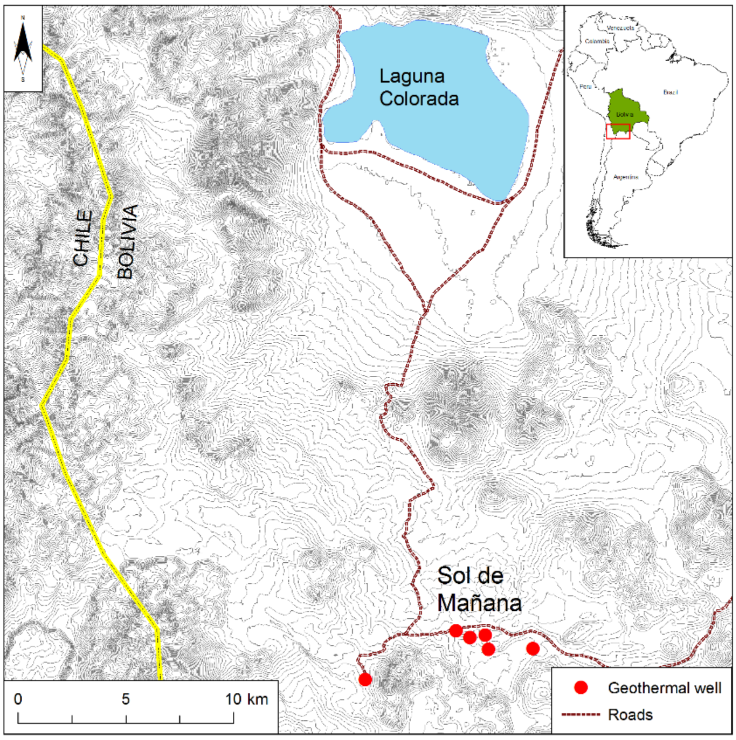

FIGURE 1: Location of the Sol de Mañana geothermal field

In 1980, ENDE carried out a prefeasibility study, and in the period 1988-1994 six deep wells were drilled confirming a reservoir temperature of 250-260°C. The drilling was carried out by the Bolivian Oil Company (YPFB) and the Italian government through the Italian Electricity Company (ENEL). Production tests performed on the wells indicated a potential of 40-50 MW_e, with possible extension up to 100-150 MW_e (ENEL, 1991). Unfortunately, due to a change in political situation the project was suspended in 1994.

In 1997, the Mexican Electricity Company (CFE) carried out an interference test, well testing and resource assessment certificating a geothermal potential of 120 MW_e for 25 years (CFE, 1997). In 2008, Japan External Trade Organization (JETRO) with West Japan Engineering Consultants, Inc. (West JEC) carried out a feasibility study for a 100 MW_e geothermal plant (JETRO, 2008). Following that study in 2010, the government of Bolivia started the planning for the financing of the construction of a 50 MW_e geothermal power plant in the Sol de Mañana field. In 2013, Japan International Cooperation Agency (JICA) with West JEC carried out well testing and resource assessment confirming the potential of 100 MW_e for 30 years in the Sol de Mañana field (JICA, 2013).

1.2 Goals of the study

The main objectives of this study are to:

- Review the available information from the Laguna Colorada Geothermal Project and literature related to geothermal assessment and modelling from the area;

- Review and collect information of preliminary studies and digitize relevant information from temperature and pressure logs, production tests, injection tests, interference tests and resource assessment;
- Review preliminary conceptual models carried out previously in order to obtain the reservoir properties;
- Analysis of temperature and pressure characteristics;
- Estimate the resource capacity using the volumetric method.

2. SOL DE MAÑANA GEOTHERMAL FIELD

2.1 Geological setting

The study area is located in southwest Bolivia, around 4900 m a.s.l. This area is comprised of Miocene-Pleistocene rock of the Andes volcanic arc extending in N-S direction generally parallel to the Pacific coast, and overlies marine and terrestrial sediments of Cenozoic-Paleogene age. The volcanic arc products are of calc-alkaline composition and vary between rhyodacites and andesite, and consists of lavas, tuffs and ignimbrites. The regional structure has two directions: N-S parallel to the magmatic arc and another NW-SW with long alignments along the recent volcanism.

The geo-volcanological mapping indicates the existence of an extensive ignimbrite unit that almost completely covers the area, and overlies an andesitic-dacitic lava sequence and possibly ignimbrites from the Neogene. The structural geology shows two orthogonal tectonic systems NNW-SSE and NNE-SSW, the first system is more pronounced and also affects the most recent formations and determines the formation of small horsts and grabens. This system is related to seismic events whose effects are still recognizable (ENEL, 1991). Figure 2 shows the stratigraphy and structural geology of the area.

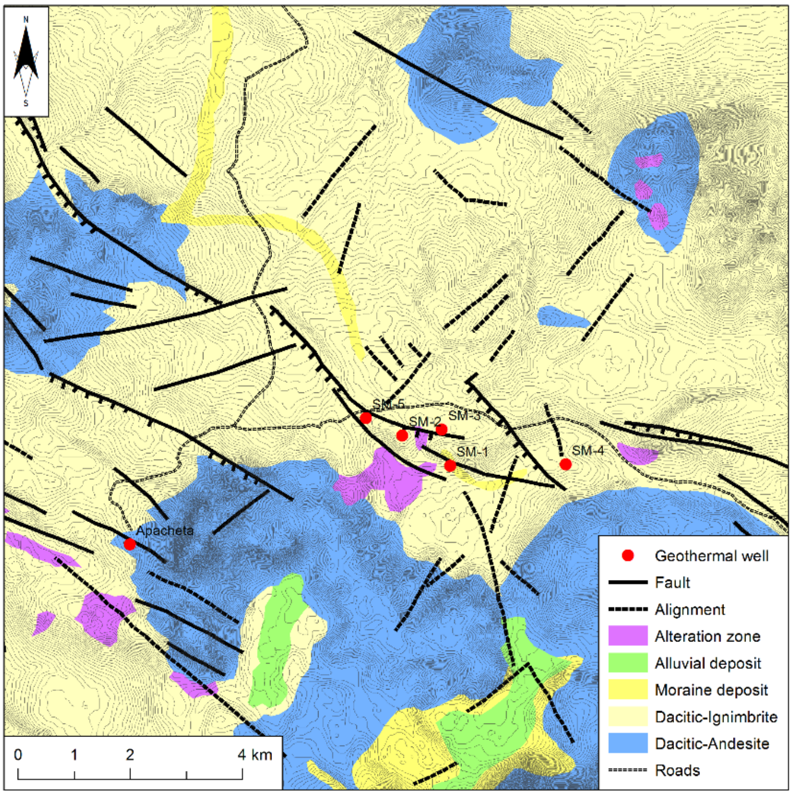

FIGURE 2: Stratigraphy and structural geology map (modified from JETRO, 2008)

The geological information suggests the existence of magmatic chambers located below the volcanic axis, indicating important heat sources in the west part of the manifestation areas (ENDE, 1986).

The structural system has caused secondary deep fracturing, which allows the hot water to rise up resulting in a heat exchange with shallower aquifers. Part of the geothermal fluid rises as vapour through faults and fractures to reach the surface in springs, resulting in hydrothermal alteration zones (CFE, 1997).

2.2 Chemistry

According to $Cl-SO_4-HCO_3$ ternary diagram, the fluid could be classified as a mature water of neutral pH with a relatively high concentration of chloride. The Na-Ka-Mg ternary diagram indicates a fully equilibrated reservoir fluid with a reservoir temperature of 280°C, however liquid from hot springs in the area show signs of mixing with cold groundwater. The temperature obtained from Na/K, H_2S, H_2S/Ar and H_2S/H_2 geothermometers are in agreement with the measured reservoir temperature (Villarroel, 2014).

2.3 Geophysics

The structural mapping is based on gravimetric and resistivity data, and the possibility that those anomalies are related to hydrothermal alterations rather than the primary rock characteristics. According to laboratory results, the rock density for ignimbrites and lavas are 2-2.7 g/cm^3, but there is not a significant difference between these two rock types. The low resistivity layer corresponds to high argillic alteration, and the circulation fluid pattern that alters the rocks is related to fracturing system (ENEL, 1991).

Recently, a magneto telluric survey (MT) was carried out in order to connect better the gravimetric and resistivity anomalies that have been identified in the exploration stages. Figure 3 shows the gravimetric and resistivity anomalies and resistivity map modified from JECTRO (2008) at 3500 m a.s.l., displaying two boundaries inferred by the data. According to the resistivity data, the reservoir could be inside these two boundaries. A comparison was made between surface resistivity and drilling data with the lithology and temperature logs in well SM-3. The main conclusion is that the cap rock would be associated with resistivity of around 30 ohmm (Ramos, 2014).

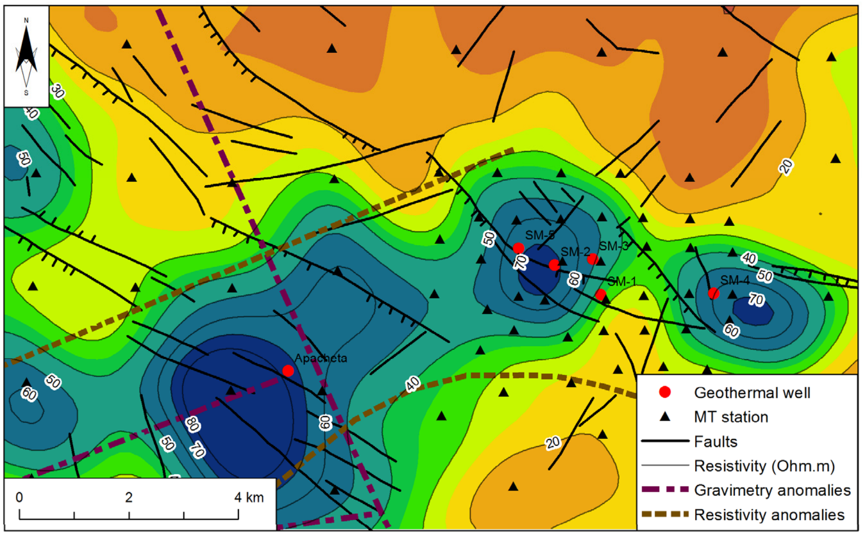

FIGURE 3: Gravimetric and resistivity anomalies and resistivity map at 3500 m a.s.l. (modified from JETRO, 2008)

According to preceding reports, the geothermal resource would be divided into two fields: Sol de Mañana and Apacheta (ENEL, 1991; JETRO, 2008). In this study the main focus will be on the Sol de Mañana field, due to better information availability.

2.4 Description of the wells in Sol de Mañana field

The deep drilling began in 1987 in the Cerro Apacheta zone, but due to discouraging results from that well the drilling continued at the Sol de Mañana field (ENEL, 1991), where five wells (Figure 4) were drilled between 1989 and 1994. The well depths vary between 1180 and 1726 m, and all the wells are vertical (see also Table 1). Only the reinjection well has a slotted liner due to a collapse at the bottom. The section A-A' (Figure 4) is described in Chapter 3.3.

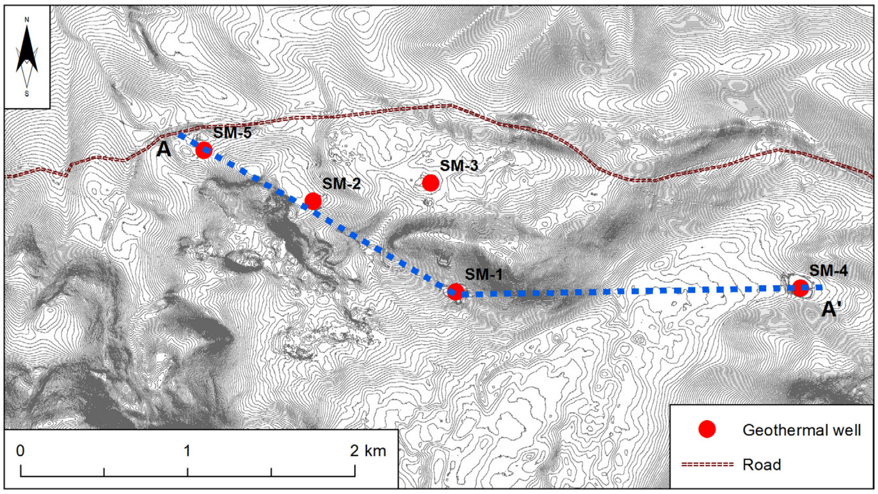

FIGURE 4: Well locations in the Sol de Mañana field

During the drilling of the wells several temperature logs were performed in order to determine the formation (undisturbed) temperature. Most of the logs were successful, except in zones with a loss of circulation, particularly in well SM-02. Temperature and pressure logs were also performed in static and dynamic conditions. However, the tests carried out at different times were not performed in all the wells. Well SM-03 was opened to production after almost 23 years.

TABLE 1: Description of wells in Sol de Mañana field

Well	Elevation (m a.s.l.)	Drilled depth (m)	Casing depth (m)	Liner	Type of well
SM-1	4859	1180	737	Open hole	Production
SM-2	4906	1486	608	Open hole	Production
SM-3	4885	1406	765	Open hole	Production
SM-4	4841	1726	1307	Slotted	Reinjection
SM-5	4904	1705	900	Open hole	Production
AP-1	5023	1602	780	Open hole	Production

In this report, the work carried out after the drilling by ENEL and ENDE in the period 1989-1994, and the well testing by CFE in 1997 and JICA in 2013, will be addressed.

3. ANALYSIS OF TEMPERATURE AND PRESSURE CHARACTERISTICS

Wells are vital components in both geothermal research and utilization, since they provide essential access for both energy extraction and information collection. A geothermal well is connected to the geothermal reservoir through feed-zones in the open section or intervals. The feed-zones are either open fractures, or permeable aquifer layers. In volcanic rocks the feed-zones are often fractures or permeable layers, such as layers between different rock formations. In some instances, a well is connected to a reservoir through a single feed-zone, while in other cases several feed-zones may exist in the open section, but often one of these is the dominant one (Axelsson, 2013).

The temperature and pressure logs are carried out during the drilling of wells, during heat-up after drilling, and during flow tests. The biggest challenge in analysing these logs is to define the temperature and pressure reservoir conditions, by determining the formation temperature profile for each well and the pressure potential of permeable zones intersected by the wells. When several wells have been drilled in an area, maps can be drawn to show the formation temperature and the pressure distribution in the geothermal reservoir. Early in the development, these maps will show the initial reservoir conditions prior to utilization. Later, when production from the field commences, the mass withdrawal from the reservoir will lead to pressure drawdown and sometimes also temperature changes in the geothermal reservoir. Temperature and pressure logs are then used to monitor the changes and map the long term response of the reservoir to the utilization (Steingrímsson, 2013).

Determining the temperature and pressure distribution in a geothermal system is a fundamental requirement in the resource assessment. The temperature distribution indicates the resource quality and the feed-zones. A cross-section map shows how the temperature and pressure varies within the reservoir horizontally and vertically. Contour plots and vertical cross-sections can then be prepared at selected depths and locations to show how the temperature varies within the reservoir either horizontally or vertically. These plots are useful for showing how hot and cold fluids interact within the geothermal system and are important in the formulation of the system model (Abdollahzadeh Bina, 2009).

According to Steingrímsson (2013), the boiling point depth curve (BPD curve) is often plotted as a reference as this curve defines the maximum possible formation temperature for a hydrothermal system. If the temperature logs do not accurately define the formation temperature, further analyses, interpretation, assumptions or pure guesses are necessary in order to estimate the formation temperature for the well.

3.1 Formation temperature tests

After the drilling of a geothermal well is completed, the well is usually allowed to recover in temperature (heat up) from the cooling caused by drilling fluid circulation and cold water injection. The heat up of a well can take from a period of few hours to a few months, but it usually takes a few months. The principal reservoir engineering research conducted during this period is repeated temperature and pressure logging. The temperature data collected during heat up is used to estimate the undisturbed system temperature, often called the formation temperature, as wells usually do not recover completely during the recovery period. The method most often applied for this estimation is the Horner method. The pressure data collected is used to estimate the reservoir pressure with the intersection of several warm-up pressure profiles, defining the pivot point. If a single feed-zone dominates a well, the pivot point defines the reservoir pressure at the feed-zone depth. If two or more feed-zones exist in a well, the pivot point defines average conditions instead (Axelsson and Steingrímsson, 2012).

3.2 Interpretation of temperature and pressure profiles

Temperature and pressure logs carried out in Sol de Mañana field were collected at different stages and by different companies:

- In 1989-1994 by ENEL and ENDE, after drilling in all the wells under static conditions;
- In1997 by CFE in all the wells under static conditions;
- In 2013 by JICA through West JEC in wells: SM-01, SM-02, SM-03 and SM-04 under static and dynamic conditions.

Unfortunately, the same measurements were not performed in all the wells, and in some cases the information was not detailed enough about the state of the wells before and during the logging of the wells. However, it was possible to digitize records of temperature and pressure logs in order to plot data from individual wells on a single graph, for better understanding and comparison.

The first logs from 1989 to 1997 were performed with mechanical tools while the last records from 2013 were performed with electronic tools, making the last logs more detailed.

3.2.1 Well SM-01

The production well SM-01 was drilled in the period 08.09.1989-13.11.1988 to 1180 m depth, and has an open interval from 737 m depth to the well bottom. During the drilling, a partial loss of circulation was identified at 762-977 m depth, and finally total loss of circulation occurred at 977-1180 m depth. The main well rock type is ignimbrite of dacite composition of variable colour, which consists of quartz crystals, plagioclase, biotite and hornblende immersed in a vitreous matrix with chaotic texture. Study on secondary minerals revealed three zones of hydrothermal alteration:

- Zone of heulandite: 0 to 400 m depth;
- Zone of quartz and chlorite: 400 to 780 m depth;
- Zone of epidote: 780 to 1180 m depth.

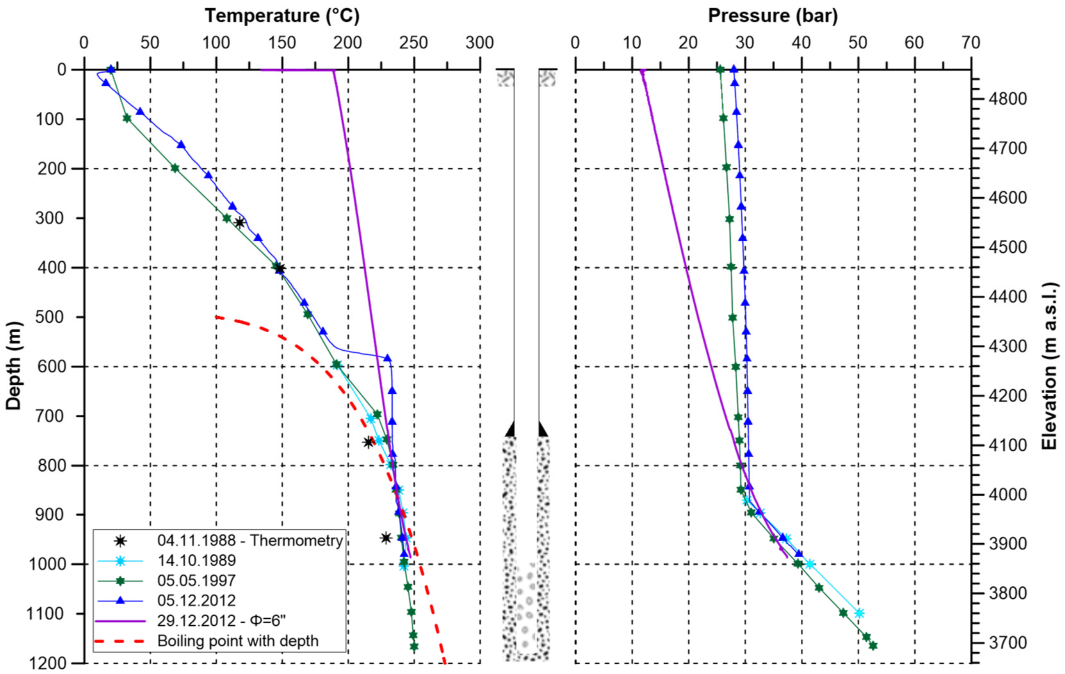

FIGURE 5: Temperature and pressure logs in well SM-01 in static and dynamic conditions

Figure 5 shows the temperature and pressure logs performed in the well. During the drilling of the well, some thermometry tests were carried out at different depths in order to assess the stabilized temperature using the Horner method. Finally, after the heating period, the well was opened to production for about 14 days (ENEL, 1989a).

The temperature gradient is around 300°C/km down to 700 m depth. This gradient could indicate an impermeable layer acting as a cap rock for the reservoir. The reservoir temperature is 240-250°C. In the interval of 860-1180 m depth the well is liquid compressed. There is a possibility that the well is in a two phase zone from 600-960 m depth, but above this depth and up to the surface the well has a gas column. In all cases, the temperature and pressure logs were carried out after a long time of heating up. The wellhead pressure in static conditions is around 28-30 bar (gas column), that allows the well to discharge without pressurization (ENEL, 1991).

3.2.2 Well SM-02

The production well SM-02 was drilled in the period 19.12.1989-17.02.1989 to 1486 m depth and has an open interval from 617 m depth to the well bottom. There was a partial loss circulation while drilling down to 920 m depth, but a total loss of circulation occurred while drilling in the interval 920-1486 m depth. As the for well SM-02, this one is characterized in the upper part by dacitic ignimbrites, followed by dacitic lavas and dacitic ignimbrites at the bottom of the well. The study of secondary minerals showed four hydrothermal alteration zones:

- Zone with clay minerals: 0 to 400 m depth;
- Zone with wairakite: 525 to 800 m depth;
- Zone with wairakite and epidote: 800 to 950 m depth;
- Zone with epidote and adularia: 950 to 1486 m depth.

Figure 6 shows the temperature and pressure logs performed in the well. The thermometry carried out to different depths were analysed using the Horner method, however the tests were affected by the loss in circulation (ENEL, 1989b).

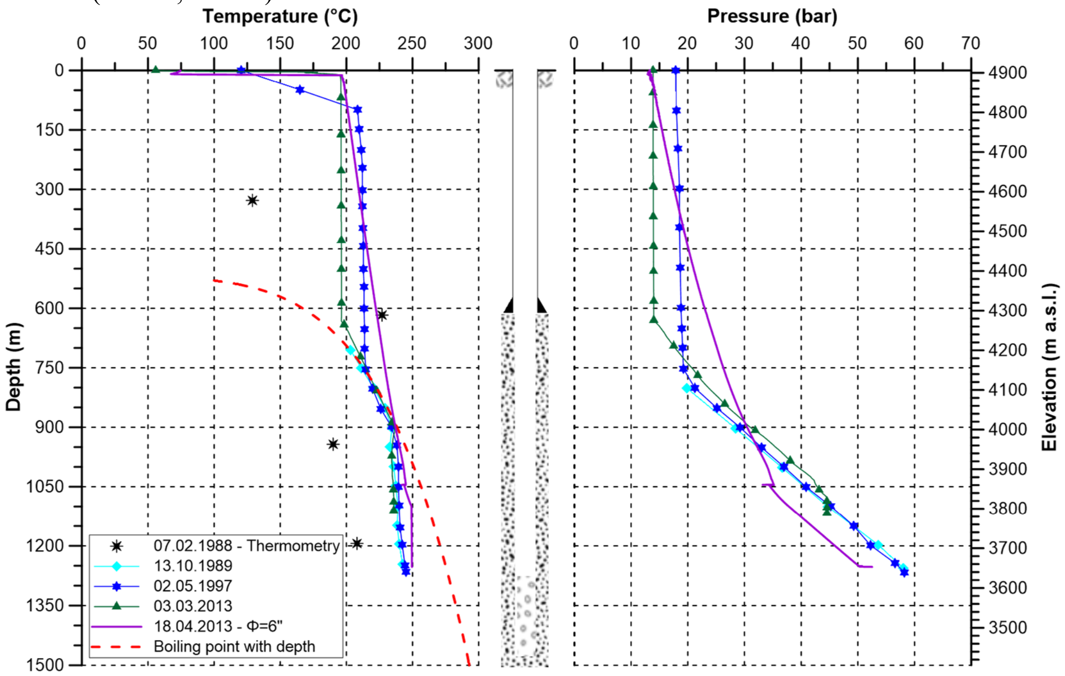

FIGURE 6: Temperature and pressure logs in well SM-02 in static and dynamic conditions

A high thermal gradient around 275°C/km is observed in the well down to 700 m depth, where the heat is transferred by conduction. Possibly there are two phase conditions in the depth range of 700-900 m depth and a low thermal gradient with temperatures within 230-242°C in the bottom section, 900-1250 m depth. The reservoir temperature is estimated about 245°C. According to the temperature logs below 900 m depth the system is liquid compressed, within 750-900 m depth it is two-phase and above this depth there is a gas column in the well.

The closed well has enough wellhead pressure (15-30 bar) to produce without stimulation. The well was open to production at the end of drilling, in 1997 and again in 2013.

3.2.3 Well SM-03

The production well SM-03 was drilled in the period 21.04.1989-05.10.1989 to 1406 m depth and has an open interval from 736 m depth to the well bottom. The drilling operation stopped after around 90 days. The drilling penetrated through impermeable formations to 900 m depth, below this depth the drilling continued with total loss circulation down to 1406 m depth. The layers are characterized by formations of dacitic ignimbrites to 970 m depth. No cuttings were returned from below that depth due to total loss circulation and it was not possible to distinguish ignimbrite in the upper layer followed by andesite (ENEL, 1990).

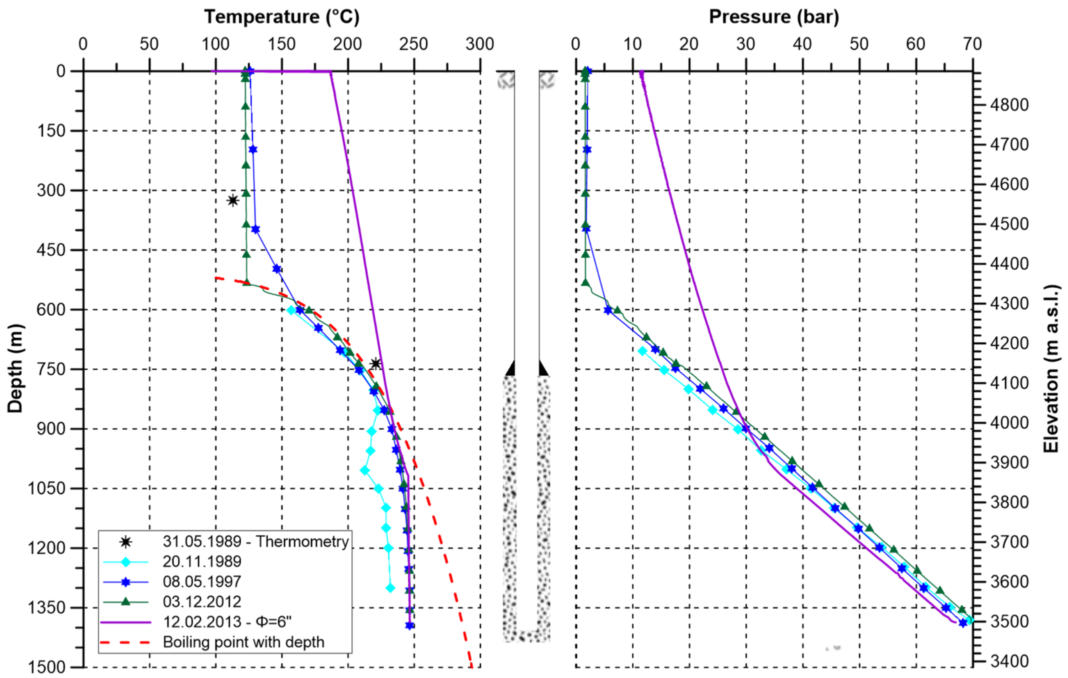

FIGURE 7: Temperature and pressure logs in well SM-03 in static and dynamic conditions

Figure 7 shows the temperature and pressure logs performed in the well. Two temperature recovery measurements were carried out at different depths and were analysed using the Horner method.

A high thermal gradient around 300°C/km in the uppermost 750 m depth of the well was identified and the first temperature log after drilling shows that the well was still heating up. According to the temperature logs below 900 m depth, the well is liquid compressed, within 600-900 m depth it is two-phase and above 600 m depth there is a gas column in the well. The reservoir temperature is close to 250°C.

3.2.4 Well SM-04

The well SM-04 was designed as a reinjection well, and was drilled in the period 31.10.1989-23.12.1989 to 1474 m depth. Due to low permeability, the injectivity index was only around 1 m^3/h/bar. The well was deepened in the period 02.12.1991-17.12.1991 to 1726 m depth (ENDE, 1994a). The well has a slotted liner from 1307 m depth to the well bottom. The well crossed impermeable formations down to 1300 m depth, but below, partial and total circulation losses were observed during drilling. The lithology penetrated was dacitic ignimbrites, andesitic lavas and dacitic ignimbrites in the bottom section of the well. The study of secondary minerals shows the following hydrothermal alteration zones:

- Zone with clay minerals: 0 to 650 m depth;
- Zone with sericite and chlorite: 650 to 1474 m depth;
- Zone with sericite, chlorite and epidote: 1474 to 1726 m depth.

Figure 8 shows the temperature and pressure logs performed in the well. The stabilized temperature log shows a constant gradient around 150°C/km down to 1400 m depth, displaying typical character for impermeable rocks with heat transfer by conduction (ENEL, 1991).

The well is liquid compressed from the surface down to the well bottom, without wellhead pressure. The thermometry indicates that the area around the well had not reached equilibrium temperature below 800 m depth (ENDE, 1994a), but the thermometry (1989) suggests a much higher temperature at 1200 m depth than was measured (2012, 1997 and 1993). The temperature measurement from 2012 is very similar to the one from 1997 indicating undisturbed temperature, except if the well had been cooled

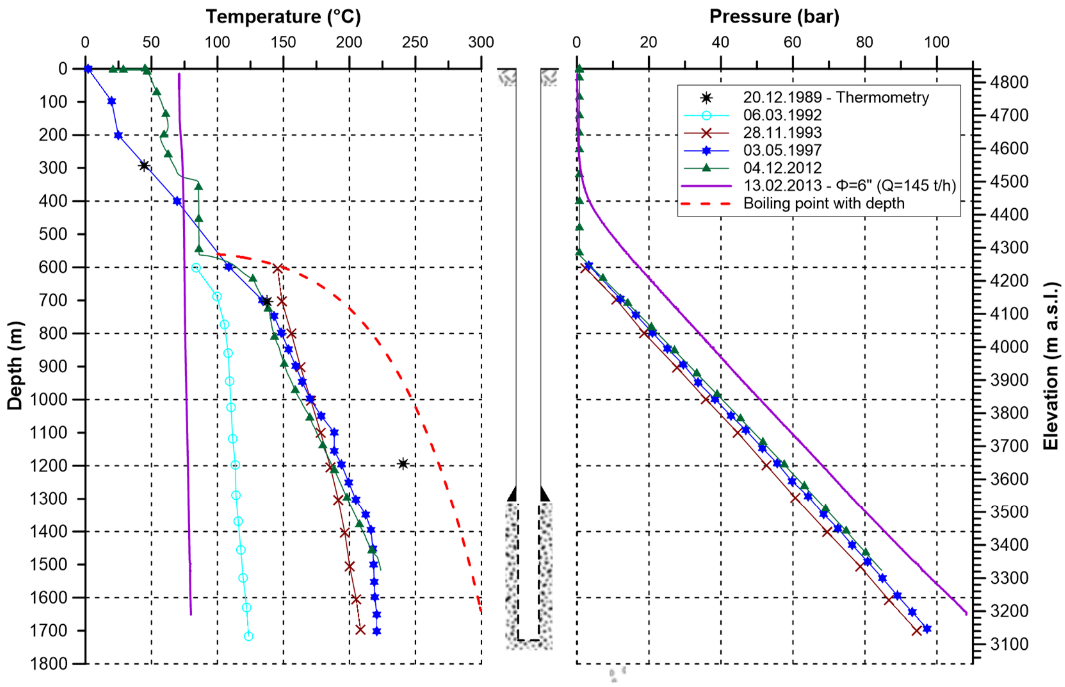

FIGURE 8: Temperature and pressure logs in well SM-04
in static and dynamic conditions

down for some reason before the last temperature measurement in 2012. The reservoir temperature would then be about 225°C.

3.2.5 Well SM-05

The production well SM-05 was drilled in the period 03.04.1992-04.11.1992 to 1705 m depth and has an open interval from 900 m depth to the bottom of the well. The drilling operations stopped for about four months due to winter conditions. The well penetrated relatively impermeable formations down to 900 m depth, with partial circulation losses. The well was drilled with total circulation loss from that depth down to the bottom. The strata are characterized by dacitic ignimbrite down to 700 m depth, continuing with andesitic pyroxene to 920 m depth and finally dacitic ignimbrite on the bottom of the well. The study of secondary minerals shows three hydrothermal alteration zones:

- Zone with clay minerals: 0 to 420 m depth;
- Zone with epidote and adularia: 420 to 900 m depth;
- Zone with epidote and orthoclase: 900 to 1700 m depth.

Figure 9 shows the temperature and pressure logs performed in the well. The temperature logs revealed gradients around 225°C/km to 1000 m depth where the heat transfer was by conduction, and below this depth by convection with reservoir temperatures around 250°C at the well bottom. The pressure log after drilling showed a decrease due to gas accumulation in the upper zone (ENDE, 1994b).

The logs also showed that below 900 m depth the well is compressed liquid, from 600 to 900 m depth in two-phase and gas exists in the upper part. During the well testing in 1997, two logs in static conditions were carried out before and after the well testing. In the last log there was an increase in temperature and it was by heating of the well after drilling (CFE, 1997).

3.3 Temperature and pressure distribution

Contour maps, both cross-sections and contour plans, show how the temperature varies within the reservoir and at the reservoir boundary. Such maps indicate the locations of conductive and convective

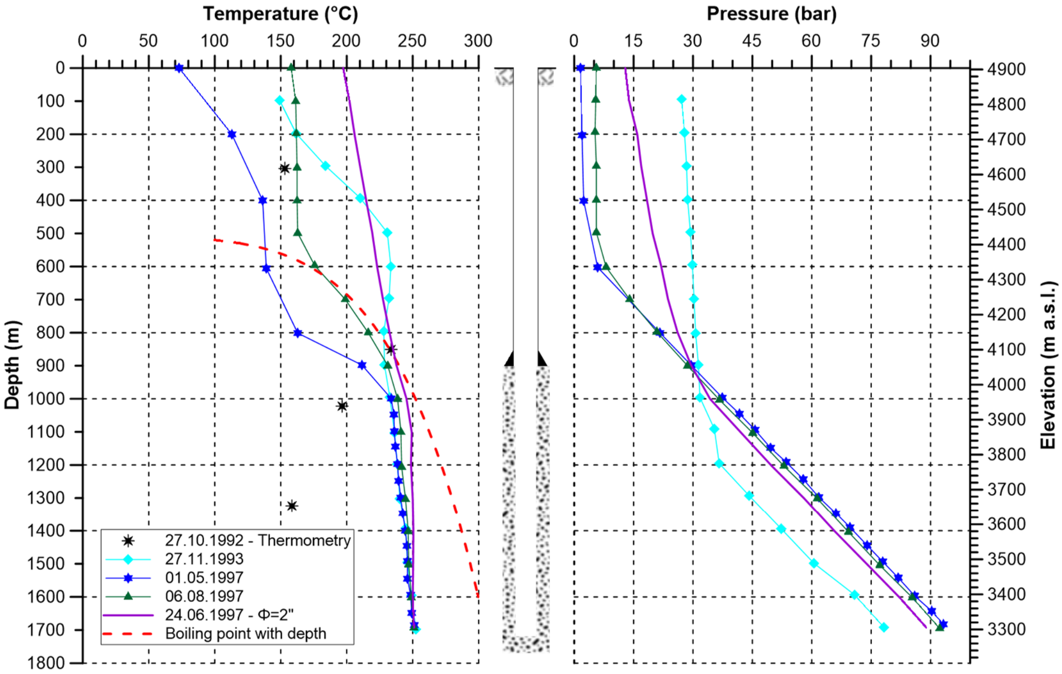

FIGURE 9: Temperature and pressure logs in well SM-05 in static and dynamic conditions

zones in the geothermal system and divide it into recharge areas, up flow zones and out flow areas. The formation temperatures maps, drawn before any exploitation starts from the reservoir, define the natural thermal state of the reservoir but maps based on temperature data from the reservoir under exploitation will reveal temperature changes caused by the production through pressure drawdown, induced fluid recharge and boiling. Temperature maps are very important in the development of conceptual models of geothermal reservoirs (Axelsson and Steingrímsson, 2012).

Figure 10 shows a vertical cross-section from the profile line A-A’ presented in Figure 4 (Chapter 2.4). The profile line A-A’ crosses through wells SM-05, SM-02, SM-01 and SM-04 (direction W-E), and the geological structure in the Sol de Mañana field.

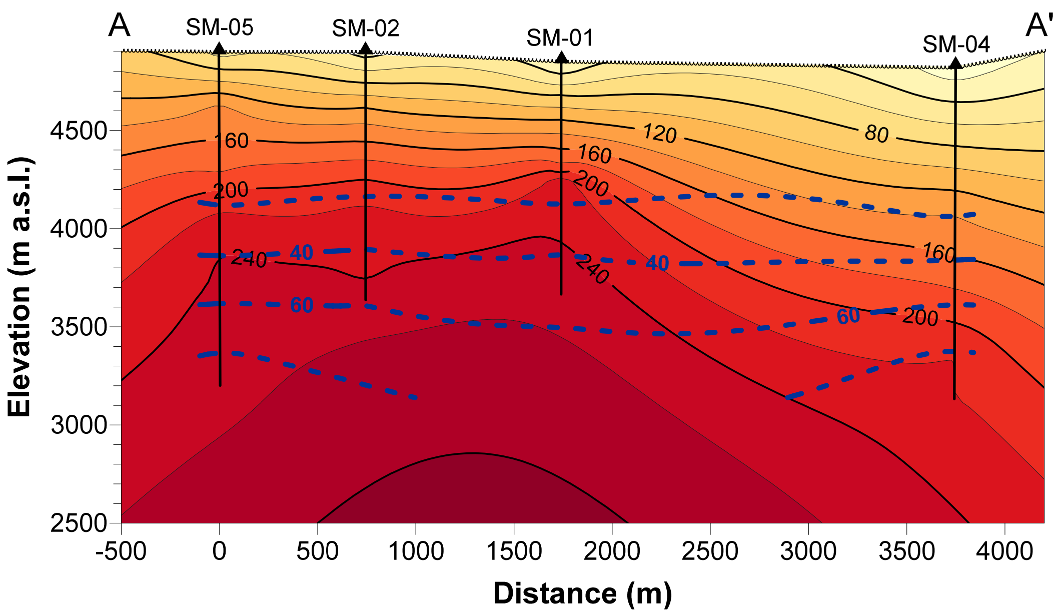

FIGURE 10: Temperature (°C) and pressure (bars) cross-section in Sol de Mañana field through wells SM-05, SM-02, SM-01 and SM-04

According to the temperature cross-section, the up flow is likely close to wells SM-01 and SM-02, and cooling is evident from well SM-04 towards the production wells. According to the pressure data, the pressure is almost constant along the same cross-sections, as presented in blue on the temperature cross-section.

Interpretation of sub-surface pressures is generally more difficult than sub-surface temperatures, because the pressure profile within the wellbore does not generally reflect the pressure profile with depth in the surrounding formation. The well pressure is often in equilibrium with the formation pressure only in the major feed zone. If there are two or more significant permeable zones, then the depth of the equilibrium will lie between these zones (Abdollahzadeh Bina, 2009).

4. WELL TESTING IN SOL DE MAÑANA FIELD

During a well test, the response of a reservoir to changing production (or reinjection) conditions is monitored. Since the response is, to a greater or lesser degree, characteristic of the reservoir properties, it is possible in many cases to infer reservoir properties from the response. Well test interpretation is therefore an inverse problem in that model parameters are inferred by analysing model response to a given input. The objectives of a well test usually fall into three major categories: reservoir evaluation, reservoir management and reservoir description (Horne, 1995).

4.1 Production well tests

Production well tests are conducted to determine the energy content (deliverability), and to analyse the flow characteristics of a well, the tests are done by measuring the fluid flow from a discharging well at different wellhead pressures (Afeworki, 2010).

During the production well test, the total flow, enthalpy and fluid chemistry are measured. Grant and Bixley (2011) refer to different methods to estimate these variables.

The first production test was carried out after drilling wells SM-01 and SM-02, the total flow and enthalpy were estimated using the Russel James method (ENEL, 1989c; ENEL, 1991). The second production test was carried out in 1997 in the wells SM-02 and SM-05, the total flow and enthalpy were estimated using the Russel James method (CFE, 1997). Finally, the last production test was carried out in 2013 in the wells SM-01, SM-02 and SM-03, the total flow and enthalpy was calculated using the Russel James method and tracer flow test method (TFT) (Villarroel, 2014).

The productivity of geothermal wells is often presented through a simple relationship between mass flow rate or production, and the corresponding pressure change. In general, the productivity of geothermal wells is a complex function of the well and reservoir parameters (Axelsson, 2013).

The most important result of a production test is the characteristic well curve. Figure 11 shows the well curve for the wells in Sol de Mañana field. It shows that the characteristic curves are similar for wells SM-01 and SM-02 for the production tests (1989, 1997 and 2013), while the wells SM-03 and SM-05 show different characterises, but they were open to production only once.

According to Axelsson (2013), the characteristic well curve for the well SM-01 and SM-02 could be consistent with two-phase inflow, and the characteristic well curve for the wells SM-03 and SM-05 are similar to liquid-phase wells.

Wells that exhibit reduction in mass flow with increasing wellhead pressures, indicate that the well is wellbore controlled. The output is said to be wellbore controlled if the wellbore size limits the production. This is normally observed in areas where the permeability is very high (Sarmiento, 2011).

4.2 Injection well tests

An injection test is conceptually identical to a drawdown test, except that flow is into the well rather than out of it. Injection rates can be often controlled more easily than production rates, however analysis of the test results can be complicated by multiphase effects, unless the injected fluid is the same as the original reservoir fluid (Horne, 1995).

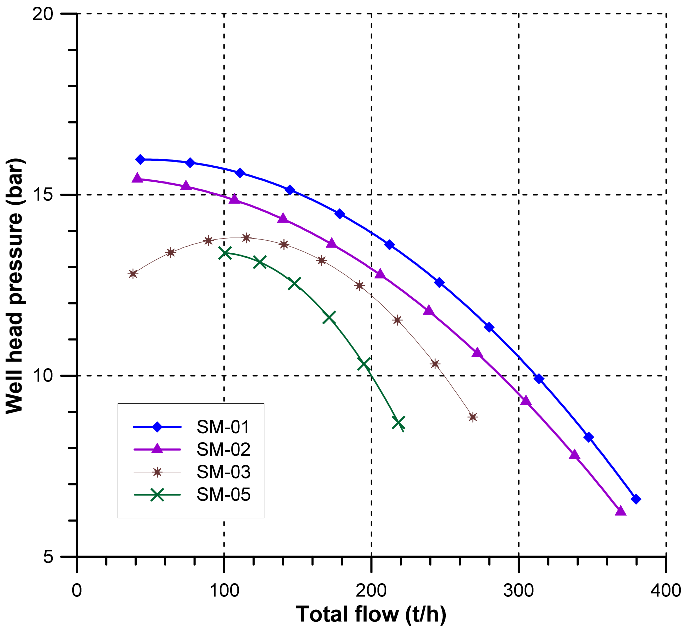

FIGURE 11: Characteristic well curves of the Sol de Mañana field

The injectivity index is defined as the change in the injection flow rate, divided by the change in the stabilized reservoir pressure. The injection tests were carried out in all the wells after drilling and several times in well SM-04. Table 2 summarizes the different injectivity tests.

TABLE 2: Injectivity index (II) at different depths in the Sol de Mañana field

Tests	Wells injectivity index [$m^3/h/bar$] / (depth [m])				
	SM-01	SM-02	SM-03	SM-04	SM-05
Tests 1 (*1989*)	2.8 (*1030 m*)	4 (*1198 m*)	13 (*1254 m*)	3 (*1413 m*)	2 (*1035 m*)
Tests 2 (*1989*)	>70 (*1180 m*)	67 (*1486 m*)	27 (*1406 m*)	2 (*1473 m*)	4 (*1350 m*)
Tests 3 (*2013*)	---	---	---	13.5 (*1500 m*)	---
Tests 4 (*2013*)	---	---	---	27.3 (*1500 m*)	---

The deeper injectivity tests in the wells SM-01, SM-02 and SM-03 give higher injectivity indexes, indicating that the wells have intersecting fracture zones with high permeability. Well SM-05 on the other hand shows only slight increase with depth. The injectivity index in well SM-04 is low compared with the wells SM-01, SM-02 and SM-03, even in the last injection test from 2013.

4.3 Interference well tests

In an interference test, one well is produced and pressure is observed in a different well (or wells), i.e. the pressure changes in the reservoir at a distance from the original producing well are monitored. An interference test may be useful to characterize reservoir properties over a greater length scale than during single well tests. Pressure changes at a distance from the producing well are smaller than in the producing well itself, so interference tests require sensitive pressure recorders and may take a long time to carry out (Horne, 1995).

In order to obtain additional information about the reservoir characteristics several interference tests were carried out, Table 3 summarizes the different interference well tests.

TABLE 3: Summary of interference tests at different stages

Year	Production well	Production period	Monitoring well	Observation period	Distance (m)	Observation
1989	SM-02	~167 days	SM-01 SM-03	100 days 167 days	1000 700	- Interruption due to technical problems. - Capillary tubing method.
1997	SM-02	~60 days	SM-01 SM-03	5 logs recording for 24 hours 4 logs recording for 24 hours	1000 700	- Pressure tool was recording alternatively for 24 hours. - It is suggested to perform this test with other equipment.
2013	SM-01 SM-03 SM-02	~23 days ~38 days ~22 days	SM-03 SM-01 SM-03	~36 days ~90 days ~48 days	670 670 700	- Capillary tubbing method. - Problems due to gas leakage.

4.3.1 Interference tests by ENEL 1989

An interference test was performed during the period 15.10.1989-22.05.1990 (with interruptions due to technical problems) by producing from well SM-02 but monitoring the pressure response in wells SM-01 (at 1050 m depth) and SM-03 (at 995 m depth). Figure 12 shows the production in well SM-02 and the pressure in wells SM-01 and SM-03 corrected at 3750 m a.s.l. during the tests.

Well SM-01: The observation in well SM-01 started after opening well SM-02, unfortunately the pressure values in the first 34 days (15.10.1989 to 18.11.1989) are not reliable since oscillation around ± 1 bar was observed in the pressure, reflecting problems with the measurement equipment. During the second period of 97 days (05.12.1989 to 12.03.1990), the measurement equipment worked correctly and the data reflected actual reservoir variations showed in Figure 12. There is no explanation about the oscillation during the period 75-100 days, as well as for the tendency in the well SM-01 to show increases in pressure before the well SM-02 was closed. Finally, during the third period of 57 days (19.03.1990 to 17.05.1990), the data is not usable due to equipment problems.

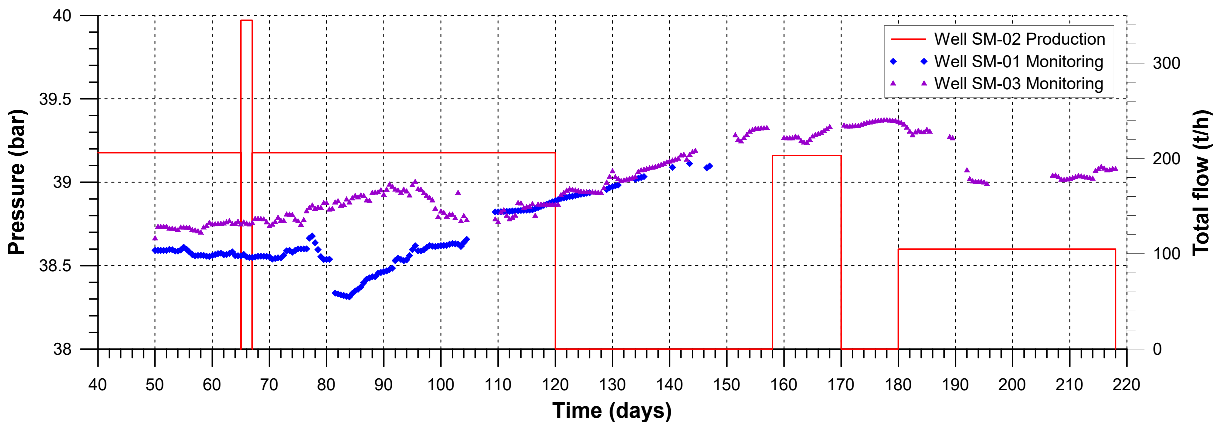

FIGURE 12: Corrected pressure monitoring at 3750 m a.s.l. (modified from ENEL, 1991)

Well SM-03: The data quality throughout the measurement period was satisfactory, except some values after about 200 days of recording (Figure 12) were possibly affected by the gas loss in the equipment, and also the data shows an oscillation during the period of 75-125 days of recording. There is a pressure increase in wells SM-01 and SM-03 during the period 130-150 days when the well SM-02 is closed.

In the period 120-150 days the wells SM-01 and SM-03 show a parallel trend where there is an increase in pressure, possibly as a response to the closure of the well SM-02, even though this trend starts in both wells before well SM-02 is closed, making it difficult to draw any definite conclusions. In the last period, after150 days of measuring, the data is hardly interpretable. The data from well SM-01 in the period 50-80 days is most promising for a quantitative interpretation (ENEL, 1991). The pressure changes in both wells is very small and could be non-related to the production from well SM-02, especially since the behaviour does not correspond in time with changes in production.

4.3.2 Interference tests by CFE 1997

Well SM-02 was opened to production for approximately four months, in this period pressure logs were performed in wells SM-01 and SM-03 aiming to observe interference between the wells, the operation basically consisted in lowering the pressure probe at 1160 m depth (SM-01) and at 1380 m depth (SM-03) and record the pressure change by 24 hours. The results in the wells show a typical liquid compressed reservoir with good permeability and an apparent connection between the wells observing an immediate response to the operation change in well SM-02 (CFE, 1997). Figure 13 shows the different pressure logs carried out in order to observe the interference between wells SM-01, SM-02, and SM-03.

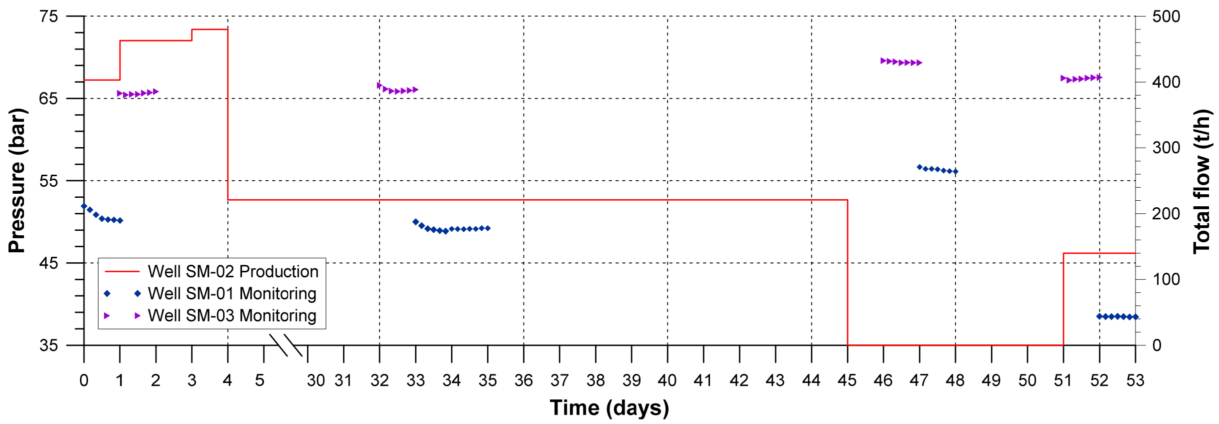

FIGURE 13: Interference tests between wells SM-01, SM-02, and SM-03 (modified by CFE, 1997)

According to the interference tests shown in Figure 13 when well SM-02 is open to production, there is an interference in well SM-01 and well SM-03. After closing well SM-02 there is an increase in pressure in both wells but it is more evident in well SM-01 than in well SM-03. Finally, when well SM-02 is opened to production the interference is higher in well SM-01 than in well SM-03. Therefore, there is a better connection between wells SM-02 and SM-01 than between wells SM-02 and SM-03.

4.3.3 Interference test by JICA 2013

The last interference test was performed using more accurate equipment in wells SM-01, SM-02, and SM-03 than in previous tests in 1989 and 1997. In the first stage, well SM-01 was opened to production and the pressure was monitored in well SM-03. In the second stage, well SM-03 was opened to production and the pressure was monitored in well SM-01. Finally, when well SM-02 was opened to production, wells SM-01 and SM-03 were monitored, but in this last stage the monitoring was stopped due to equipment problems, when well SM-02 was still producing (JICA, 2013). Figure 14 shows the production and pressure during the tests.

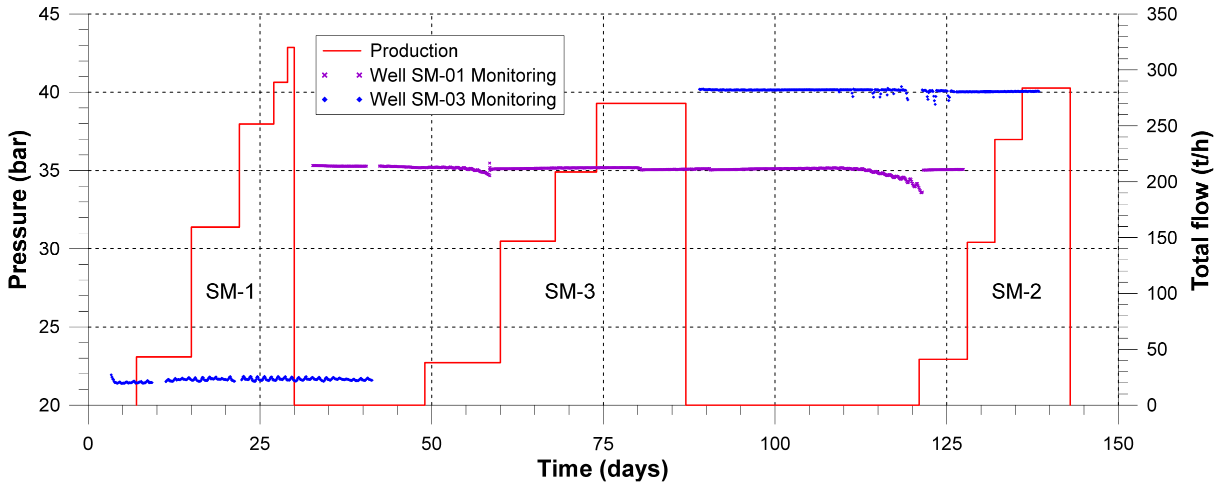

FIGURE 14: Production and pressure monitoring during the interference well testing (modified from JICA, 2013)

The pressure changes between wells SM-01 and SM-03 shown in Figure 14 are very small in relation to production of well SM-02 during the interference tests, it could be related to reservoir extension.

The different interference tests show more connection between wells SM-01 and SM-02 than wells SM-01 and SM-03, and also the geological structure map in Figure 2 (Chapter 2.1) shows a fault that crosses wells SM-05, SM-02 and between the wells SM-01 and SM-03. Therefore, the interference test confirms the geological connection between the wells SM-01 and SM-02.

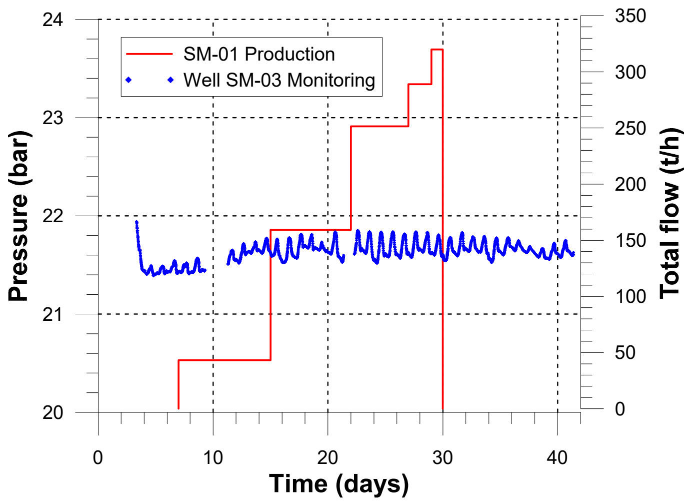

FIGURE 15. Production and pressure monitoring in the well SM-01 and SM-03 (modified from JICA, 2013)

During the production from well SM-01 the monitoring in well SM-03 showed atypical patterns as can be seen in Figure 15. The data shows a cyclical performance with one day periods. Grant and Bixley (2011) make references to changes in barometric pressure and the Earth tides that could apply here for well SM-03. The pressure changes are relatively small and most likely not connected to the production from well SM-01. Barometric pressure changes usually cause long-period pressure changes in wells that have aquifers that are connected to the atmosphere.

Leaver (1986) mentions that the increased use of sensitive quartz crystal gauges for pressure measurements has meant greater emphasis on filtering out earth tide and barometric effects to obtain a clean interference pressure response. The response of reservoirs to barometric pressure, earth and oceanic tides and rainfall has long been observed with the magnitude of the pressure response depending on the fluid viscosity, permeability, porosity and total compressibility. Barometric variations can produce reservoir responses of more than 8 kPa while earth tide responses in the reservoir are usually less than 1 kPa.

5. RESOURCE ASSESSMENT USING VOLUMETRIC METHOD

Geothermal resource assessment is a process of evaluating surface discharge and downhole data, and integrating it with other geoscientific information obtained from geological, geophysical and geochemical measurements. An assessment of geothermal resources can be made during the reconnaissance and exploratory stage prior to drilling of wells, taking into account the extent and characteristics of the thermal surface discharges and manifestations, geophysical boundary anomaly, the geological setting and subsurface temperatures obtained from geothermometers. An updated resource assessment can be made after drilling a number of wells and after the wells have been put into production, to forecast the future performance of the field. The use of simple volumetric calculations in initially committing a power plant capacity has proven that it can reliably predict the minimum commitment for a field (Sarmiento and Björnsson, 2007).

5.1 Thermal energy calculation

The volumetric method refers to the calculation of thermal energy in the rock and the fluid which could be extracted based on specified reservoir volume, reservoir temperature, and reference or final temperature. This method is patterned from the work applied by the USGS to the Assessment of Geothermal Resources of the United States (Muffler, 1979). In their work, the final or reference temperature is based on the ambient temperature, following the exhaust pressures of the turbines for electrical generation (Sarmiento et al., 2013).

The equation used in calculating the thermal energy for a liquid dominated reservoir is as follows:

$$Q_T = Q_r + Q_w \tag{1}$$

and

$$Q_r = Ah\left[\rho_r C_r (1-\varphi)\left(T_i - T_f\right)\right] \tag{2}$$

$$Q_w = Ah\left[\rho_w C_w \varphi\left(T_i - T_f\right)\right] \tag{3}$$

where: Q_T = Total thermal energy (kJ/kg);
Q_r = Heat in rock (kJ/kg);
Q_w = Heat in water (kJ/kg);
A = Area of the reservoir (m^2);
h = Average thickness of the reservoir (m);
C_r = Specific heat of rock at reservoir condition (kJ/kg°K);
C_w = Specific heat of liquid at reservoir condition (kJ/kg°K);
φ = Porosity;
ρ_r = Rock density (kg/m^3);
ρ_w = Water density (kg/m^3);
T_i = Average temperature of the reservoir (°C); and
T_f = Final or rejection temperature (°C).

If the reservoir has a two-phase zone existing at the top of the liquid zone, it is prudent to calculate the heat component of both the liquid and the two-phase or steam dominated zone of the reservoir. However, a comparison made by Sanyal and Sarmiento (2005) indicates that if merely water were to be produced from the reservoir, only 3.9% of the stored heat is contained in the fluids; whereas, if merely steam were to be produced from the reservoir, only 9.6% of the stored heat is contained in the fluids. If both water and steam were produced from the reservoir, the heat content in the fluids is somewhere between 3.9 and 9.6%. Conclusively, majority of the stored heat is contained in the rock and it does not matter whether one distinguishes the stored heat in water and steam independently (Sarmiento et al., 2013).

The possible size of a new power plant that could be supported by the resource in question is based on the following equation:

$$P = \frac{Q_T R_f C_e}{P_f t} \tag{4}$$

where: P = Power potential (MW_e);
R_f = Recovery factor;
C_e = Conversion efficiency;
P_f = Plant factor; and
t = Time in years (economic life).

The *recovery factor* (R_f) refers to the fraction of the stored heat in the reservoir that could be extracted to the surface. It is dependent on the fraction of the reservoir that is considered permeable and on the efficiency by which heat could be swept from these permeable channels. Figure 16 shows a correlation between recovery factor and porosity proposed by Muffler (1979).

The *conversion efficiency* (C_e) takes into account the conversion of the recoverable thermal energy into electricity. More accurately, the conversion can be estimated in two stages; first the conversion of the thermal energy into mechanical energy and later the conversion of the mechanical energy into electrical energy. This is not considered necessary, in view of all the uncertainties involved in the volumetric assessment method, so applying a single thermal-mechanical-electrical efficiency is considered sufficiently accurate. Figure 17 shows the correlation between thermal conversion efficiency and reservoir temperatures presented by Nathenson (1975) and Bödvarsson (1974).

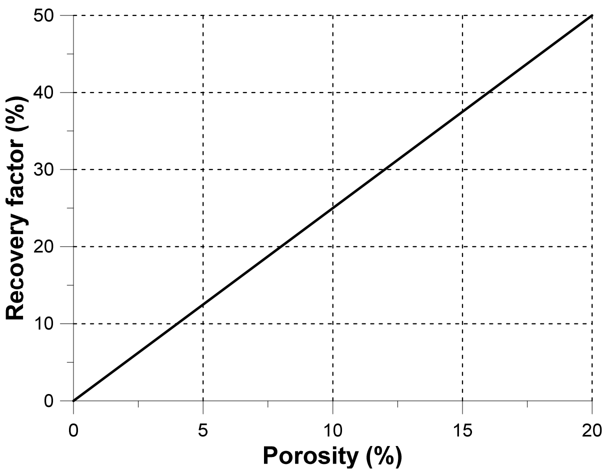

FIGURE 16: Correlation between recovery factor and porosity (From Muffler, 1979)

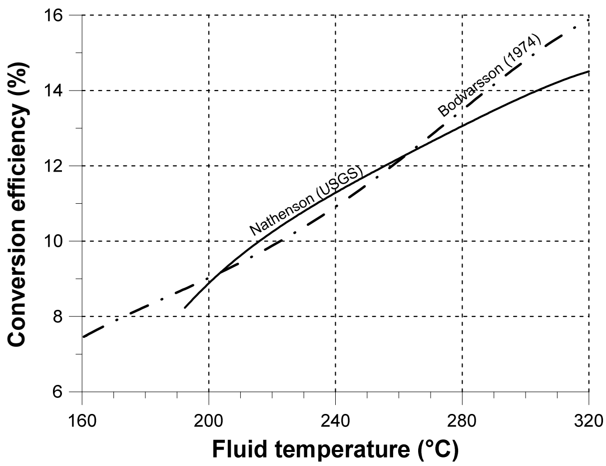

FIGURE 17: Correlation between thermal conversion efficiency and reservoir temperatures (From Nathenson, 1975 and Bödvarsson, 1974)

The *economic life* (t) of the project is the period it takes the whole investment to be recovered within its target internal rate of return. This is usually 25-30 years.

The *plant factor* (P_f) refers to the plant availability throughout the year taking into consideration the period when the plant is scheduled for maintenance, or whether the plant is operated as a base-load or peaking plant. The good performance of many geothermal plants around the world places the availability factor between 90 and 97% (Sarmiento et al., 2013).

5.2 Parameters estimated

The parameters required for the volumetric assessment were estimated following the guidelines of Sarmiento et al. (2013), based on earlier studies in conceptual model and resource assessment by ENEL (1989), CFE (1997), JETRO (2008), JICA (2013), Ramos (2014) and Villarroel (2014).

Surface area of the geothermal system: The size of the Sol de Mañana field is not yet fully known, therefore defining the extension of the reservoir can be difficult, even when many wells have been drilled (Grant and Bixley, 2011). Information on the extent of a geothermal system is usually assumed from the resistivity measurements. In Ramos (2014) a correlation was made of geophysical anomalies with drilling data to obtain a possible reservoir extension. Figure 18 shows the surface area limits for two scenarios. Scenario I which considers geophysical anomalies from the exploration reports for the Sol de Mañana field in 1989, and scenario II which considers geophysical anomalies including the Apacheta field. Table 4 summarizes the surface estimated for both scenarios.

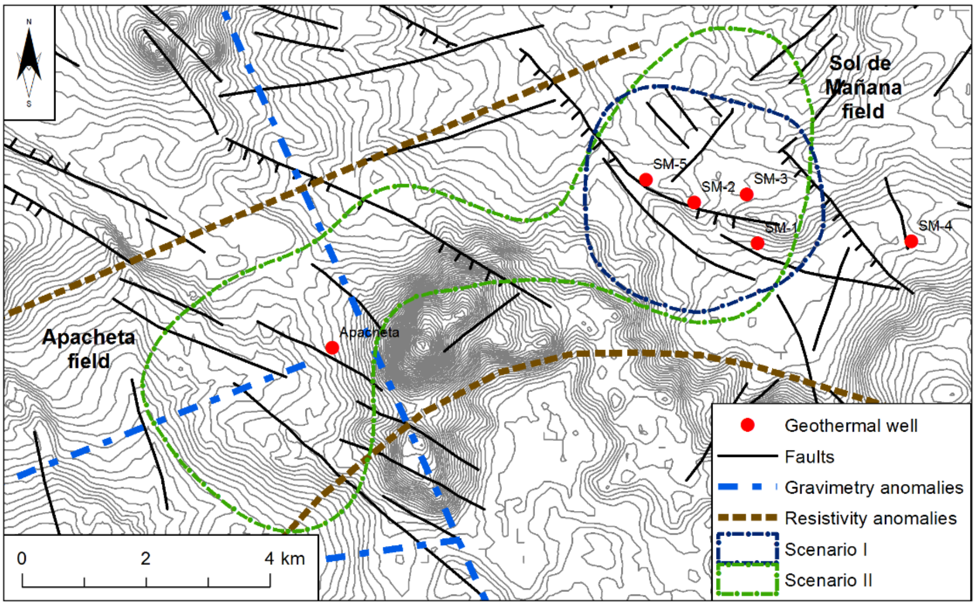

FIGURE 18: Reservoir boundaries considering two scenarios

TABLE 4: Parameter used to estimate probability distribution for Monte Carlo simulation

Input parameters	Units	Minimum	Most likely	Maximum	Type of distribution
Surface area (scenario I/II)	km^2	5/5	7/20	13/45	Triangular
Thickness	m	1000	1500	2000	Triangular
Rock density	kg/m^3		2600		Single value
Porosity	%	5	8	10	Triangular
Rock specific heat	J/kg°C		850		Single value
Temperature	°C	230	250	280	Triangular
Fluid density	kg/m^3	827	814	750	f(temp)
Fluid specific heat	J/kg°C	4683	4770	5286	f(temp)
Recovery factor	%	13	20	25	Triangular
Conversion efficiency	%	10	12	14	Triangular
Plant life	years		25/50		Single value
Reinjection temperature	°C		150		Single value

Reservoir thickness: The reservoir thickness was estimated from the temperature profiles, the depth to the reservoir was considered to be where the temperature data becomes almost constant. The lower depth is more difficult to estimate since none of the wells completely penetrates the reservoir. The minimum thickness is therefore assumed to be to the bottom of the deepest well.

Reservoir temperature: The minimum and most likely reservoir temperatures were estimated from the temperature profiles and the maximum temperature from chemistry studies.

Recovery factor and conversion efficiency: In both cases were estimated using the relations showed in Figure 16 and Figure 17.

Rock and fluid parameters: The rock properties were obtained from exploration reports in 1989. The fluid parameters are functions of thermodynamic tables.

Table 4 summarizes the parameters obtained according to the available information from the reports mentioned in the text above. Scenarios I and II are evaluated for different exploitation period.

5.3 Results

The thermal energy or the plant capacity is usually plotted using the relative frequency histogram and the cumulative frequency distribution. The relative frequency of a value or a group of numbers (intervals or bins) is calculated as a fraction or percentage of the total number of data points (the sum of the frequencies). The relative frequencies of all the numbers or bins are then plotted (Sarmiento et al., 2013). Results obtained for scenario I (maximum surface area of 13 km^2), calculated for a period of 25 years through the Monte Carlo simulation are displayed in Figure 19.

The results for the first scenario shows that the most likely value for the power production capacity is 75 MW$_e$ for a plant life of 25 years. Also, from the 80% acceptance range, the results of the simulations are that the estimated power production will be in the range of 57-124 MW$_e$ for 25 years (Figure 19a). Furthermore, the cumulative frequency, with 90% probability, shows that the resource capacity will be at least 57 MW$_e$ for 25 years (Figure 19b).

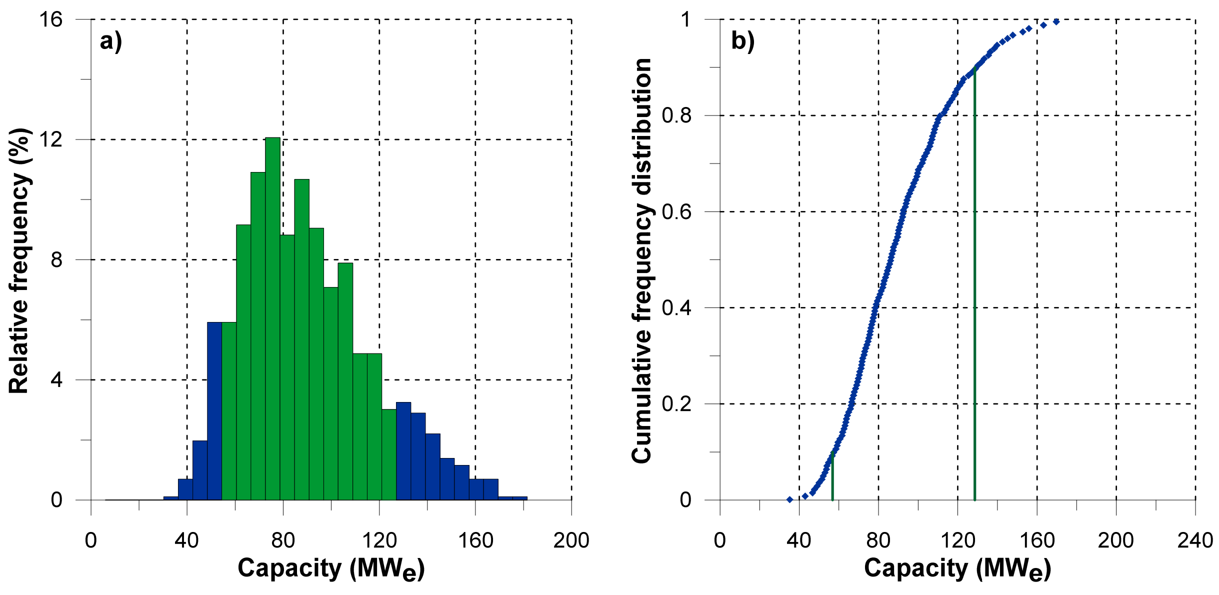

FIGURE 19: Simulation results for scenario I (13 km^2 maximum area), calculated for 25 years:
a) relative frequency of the power production capacity
b) cumulative frequency of the power production capacity

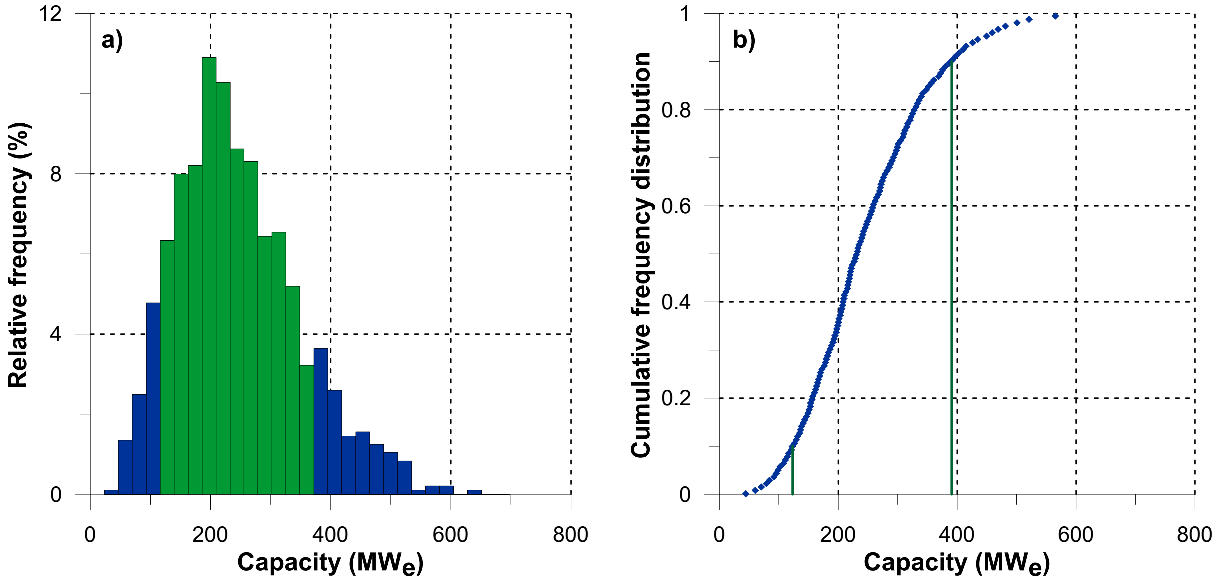

FIGURE 20: Simulation results for scenario II (45 km^2 maximum area), calculated for 25 years:
a) relative frequency of the power production capacity
b) cumulative frequency of the power production capacity

Results obtained for scenario II (maximum surface area of 45 km^2), calculated for 25 years, through the Monte Carlo simulation are displayed in Figure 20.

Similarly, results for this second scenario shows that the most likely value of the power production capacity is 214 MW_e for a plant life of 25 years. Also, the estimated power production will be in the range of 125-394 MW_e (80% acceptance range, Figure 20a) and the cumulative frequency shows that the resource capacity will be at least 125 MW_e (with 90 % probability, Figure 20b).

Finally, Table 5 summarizes the simulation results for scenarios I and II. As was expected, scenario I is more conservative than scenario II. The difference between the two scenarios lies in the estimated surface area. The first considers only the Sol de Mañana field but the second considers the Apacheta field as well, but the results of the geophysical exploration indicate that the resource might be extended to that area.

TABLE 5: Monte Carlo simulation results

Most likely parameters	**Scenario I**		**Scenario II**	
	25 years	**50 years**	**25 years**	**50 years**
Electric power (MW_e)	75	38	214	107
Monte Carlo simulation results				
90% above (P10 MW_e)	57	28	125	62
90% below (P90 MW_e)	124	64	394	196

6. CONCLUSIONS AND RECOMMENDATIONS

The main conclusions of the project are as follows:

- The review of the all available data on the Sol de Mañana geothermal field has revealed the relevance and quality of the data in order to evaluate and suggest further studies on the field.

- The general geological setting of the Sol de Mañana geothermal field is well defined, as is the structural geology, heat source and the local stratigraphy.
- Geophysical data along with temperature and pressure logs were used to outline the size of the geothermal area, giving two possible scenarios for the surface extension of the area of 5-13 km^2.
- The temperature logs indicate a reservoir temperature of about 250°C and over 1000 m thickness of the reservoir.
- The characteristic curves for the wells show similar characteristics in wells SM-01 and SM-02 (two-phase inflow) that are different from wells SM-05 and SM-03 (liquid-phase inflow).
- The high injectivity index in wells SM-01 and SM-02 indicates that these wells intersect highly permeable zones that correlate with geological structure in the area.
- The interference test shows less connection between wells SM-02 and SM-03 than wells SM-02 and SM-01.
- The review of conceptual models that exist for the area helped getting the reservoir parameters in order to use them for the resource assessment.
- The resource assessment using the volumetric method with the exploration data and well logs have allowed to obtain the most likely potential of 75 MW_e for 25 years for the Sol de Mañana geothermal field.

The main recommendations for this project are as follows:

- To continue with the analysis of relevant information in order to improve and update the conceptual model and continue with the resource assessment using numerical methods.
- To expand the geophysical survey to confirm the anomalies identified in the exploration stage, in order to define the reservoir limits in the Apacheta field.
- To work on a well testing plan in order to obtain better quality data in the following project stages.
- To calibrate equipment for next well tests.
- In order to outline the reservoir extension, it is necessary to expand the drilling area, especially southwest of the Sol de Mañana field.

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