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Lumped Parameter Model of the Miravalles Geothermal Field, Costa Rica

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ABSTRACT

Full-scale exploitation started in the Miravalles Geothermal Field when the first 55 MWe unit was commissioned in 1994. Several numerical models mostly using TOUGH2 and other similar codes have been developed since commercial exploitation and these numerical models have aided the decision-making process in the management of the field.

A lumped parameter model of the Miravalles reservoir was developed to provide another tool for reservoir management. This model was made based on the long-term pressure monitoring data of well PGM-09 and the total and net mass extraction rates in the whole field. Lumped parameter modeling using the other monitoring wells located around the field with shorter pressure monitoring data is also conducted. Good pressure matches were obtained, and some production scenarios were simulated for forecasting the future pressure response of the reservoir.

1. INTRODUCTION

The Miravalles Geothermal Field is a high-temperature liquid-dominated reservoir and has been under commercial exploitation since 1994, when its first power plant unit came online. Further development has added four more units, the last one commissioned in late 2003, which increased the installed capacity of the field to 163 MWe (Vallejos et al, 2005).

The main productive area is around 10 km^2, where most of the actual productive wells are located (Figure 1). However, there are good evidences that the reservoir area is much bigger. The actual proven productive area can be extended to about 15 km^2, since some of this area is used for reinjection purposes (Figure 2). Wells PGM-22, 24, 28 and 29 are used as injector; however, they are capable of producing (the latter two can produce 10 and 12 MWe each).

2. PRODUCTION HISTORY

The Instituto Costarricense de Electricidad (ICE) commissioned the first 55 MWe power plant in March of 1994. However, this plant works in a regular basis on nearly 60 MWe. Between 1995 and 1998 three 5 MWe wellhead units were added and produced an additional 15 MWe (but consuming a steam-rate equivalent to 30 MWe, compared with the first unit). Two of them, owned by Comisión Federal de Electricidad de Mexico were retired in August 1998 and January 1999, and the third one is producing sporadically. A second 55 MWe unit was commissioned in August 1998. Another 27.5 MWe power plant was commissioned in March 2000 and operated under a BOT contract for Geoenergía de Guanacaste, a subsidiary of Oxbow-Marubeni. All of these plants are single-flash type units. The last unit added, commissioned in November 2003 by ICE, is a 18 MWe binary-type unit. Under this scheme, ICE is the sole owner and operator of the field.

There have been some changes in the production and injection strategies in the field. From 1994 to 1998, two thirds of the total waste brine was injected to the western part of the field (equally distributed in wells PGM-22 and PGM-24) and the rest in the southern part of the field (wells PGM-16 and 26). From 1998 to 2000, the production was doubled, and so the extraction and injection rates. The injection to the west decreased in half the previous rate, and the balance was shifted to the wells in the southern part (PGM-16, 26, 51, 52, and 56). From 2000 to 2002, the production was again increased by 25%, and injection was directed to the south. From November 2002 to date, injection to the south was decreased similar to the injection levels in 1998 and redirected to the west (PGM-22 and PGM-24). This injection strategy was done to minimize the pressure drawdown observed in the field based on the reservoir monitoring conducted and the results of the numerical modeling studies (GeothermEx Inc., 2002).

Figure 3 shows the mass production observed in Miravalles. It is obtained by correlating the wellhead pressures of the different wells with their respective output curves. Day 0 corresponds to March 25, 1994 (Vallejos, 1996).

3. RESERVOIR PRESSURE MONITORING

Monitoring of the reservoir pressure drawdown started three months after the commissioning of the first unit in March 1994. However, before the commissioning of this unit some mass extraction took place for well testing during an approximate five-month testing period (power plant tests, pipeline cleaning and connection of the different wells with their respective separation units). This mass extraction period prior the plant commissioning had to be accounted and distributed for calculation purposes (Vallejos, 1996).

Three downhole pressure data gathering system were installed in June 1994 to monitor the reservoir response (Vallejos et al, 1995). The monitoring system was later replaced in the middle of 1998 and additional two units were installed. The reservoir pressure was also monitored by taking hydraulic water levels in all the idle wells (Castro, 1999). Among these wells there are PGM-58, 64, 15, 23, 25, 27, 59 and 35.

Well PGM-09 was the first well utilized for pressure drawdown monitoring. Other wells located in different places around the field (Figure 2) have been used as continuous monitoring wells (PGM-08, PGM-28, PGM-52, PGM-47, PGM-25, PGM-59) for different amounts of time. However, well PGM-09 has the most extended and complete pressure drawdown history observed. The different pressure drawdowns observed around the field are shown in Figure 4.

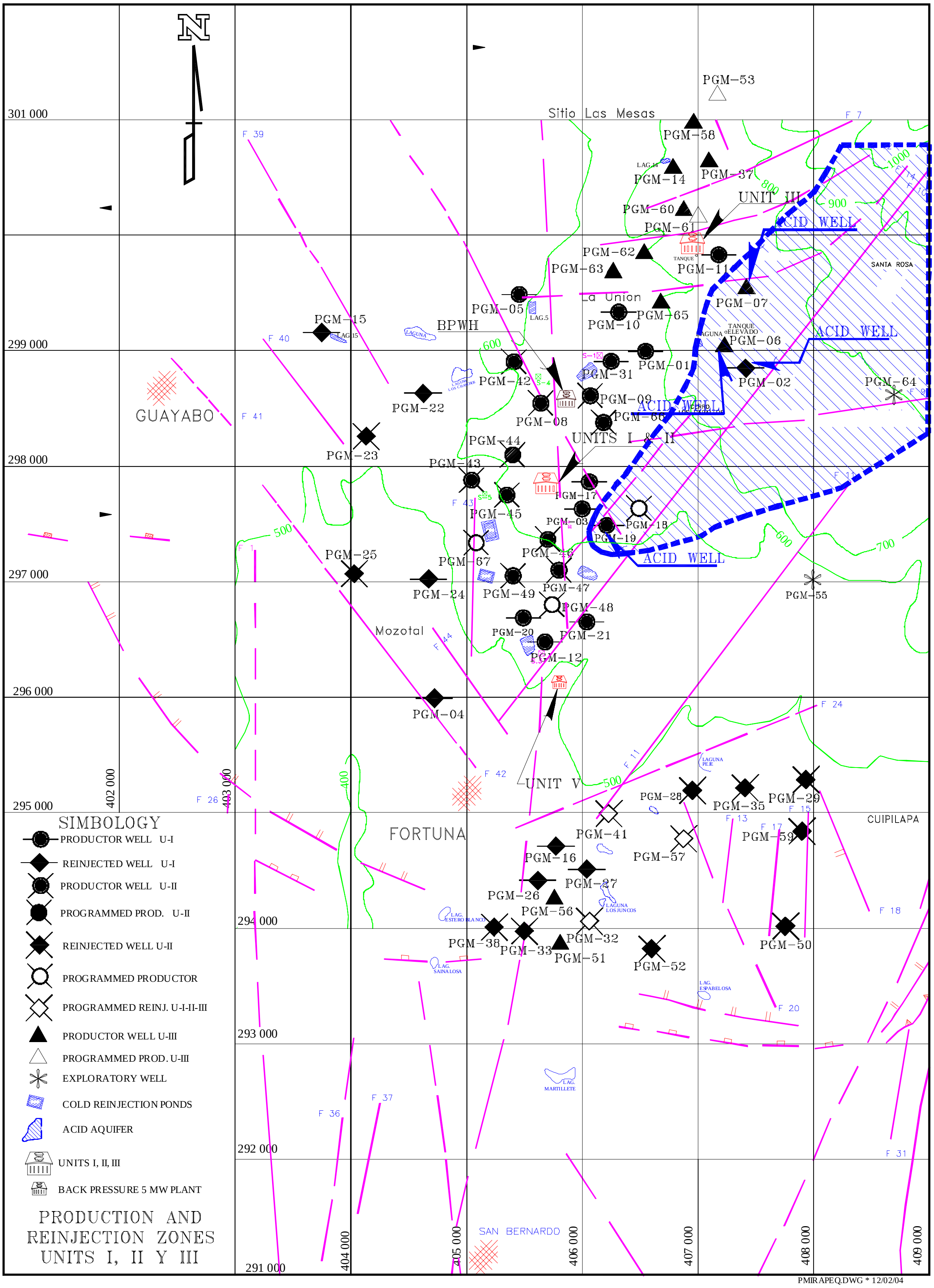

Figure 3. The Miravalles Geothermal Field.

Since the pressure drawdown monitoring system was not available prior the commissioning of the power plant, an initial reference pressure for PGM-09 and other monitoring wells was missing. In order to find this reference pressure and thus convert the collected pressure difference data in well PGM-09 to absolute pressure, some calculations were made for finding this value (Vallejos, 1996). This same procedure was followed with the other monitoring wells, taken also into account the pressure drawdown observed in the reservoir history.

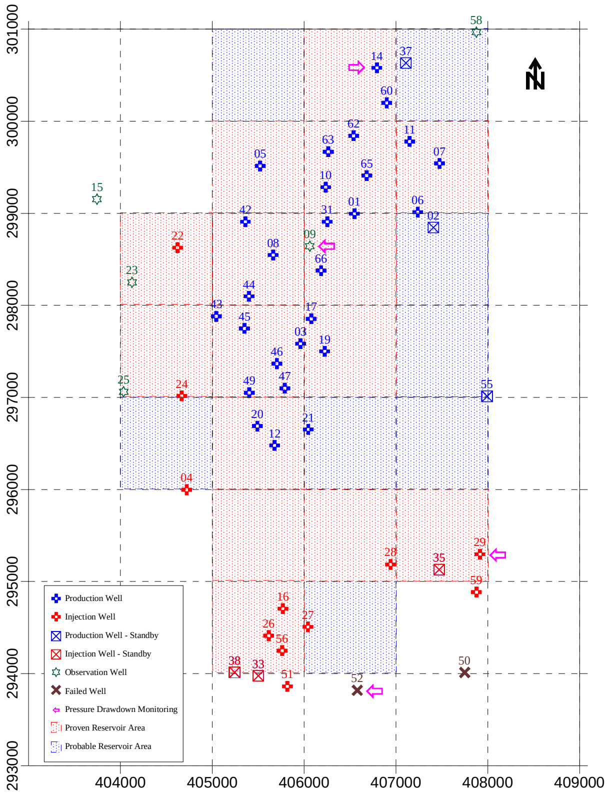

Figure 2: Schematic View of the Miravalles Field.

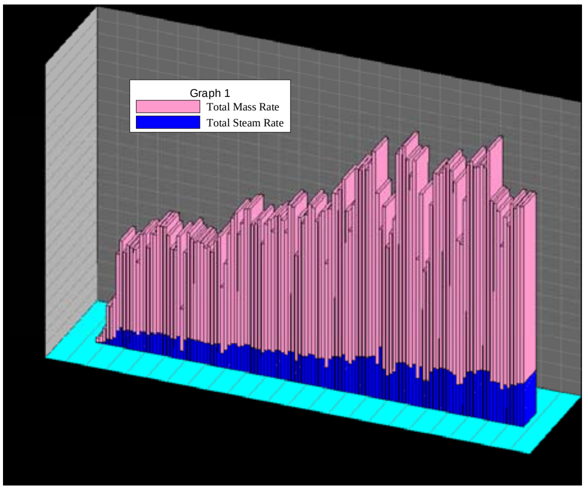

Figure 3. Production at the Miravalles Field from October 1993 to April 2004.

3.1 Well PGM-09

Well PGM-09 is located at the center part of the field, and it has been used as monitoring well since June 1994 to the present. Because of its location, the well is believed to best represent the overall pressure drawdown of the field due to its closeness to the main mass extraction area of the field.

In ten years, the overall pressure drawdown in well PGM-09 was almost 20 bar, giving a drawdown rate of about 2 bars per year. This decline has shown three distinct responses (Figure 4) over the production history: an initial response starting at the first plant commissioning time in early 1994; a second behavior related to the second plant commissioning in late 1998; and the third one when the third unit started operations by middle of 2000.

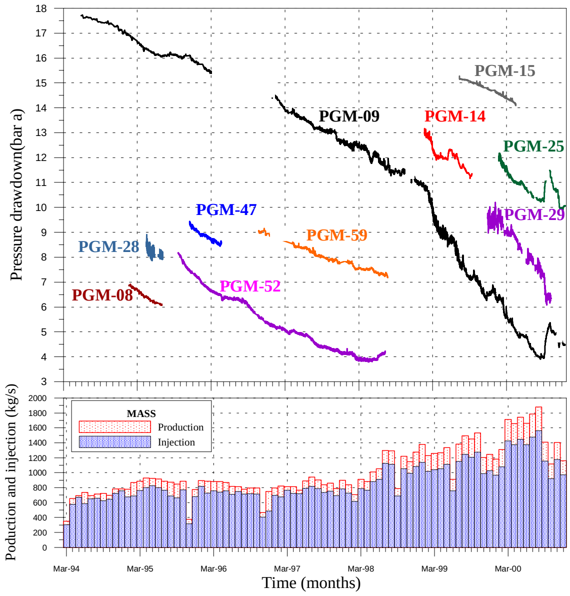

Figure 4. Pressure Decline Trends in different monitoring wells (from Castro, 2001).

3.2 Well PGM-14

Well PGM-14 is located at the northern part of the field, and it was used as monitoring well for about eight months in 1999. The Miravalles reservoir has a main inflow of 250-260 ºC fluid coming from the northeastern part of the field, and the upflow is believed to be near well PGM-11 (close to PGM-14). Because of its location, well PGM-14 was initially believed to be less affected by pressure drawdown compared to the wells located at the central part of the field.

In those eight months, the overall pressure drawdown in well PGM-14 was 1.82 bar, giving a drawdown rate of about 2.82 bar per year (Figure 4).

3.3 Well PGM-29

Well PGM-29 is located at the southeastern part of the field, and it was used as monitoring well for about ten months between 1999-2000. This part of the reservoir is slightly different form the rest of the Miravalles reservoir, and is characterized by a sodium-chloride bicarbonate aquifer that presents severe $CaCO_3$ scaling at depth. This condition is observed in all the wells of Miravalles, but is higher in this well than the other ones.

In those ten months, the overall pressure drawdown in well PGM-29 was 3.38 bar, giving a drawdown rate of about 3.95 bar per year (Figure 4).

3.4 Well PGM-52

Well PGM-52 is located at the southern part of the field, and it was used as monitoring well for about 34 months between 1995-1998. This part is the main injection area of the field (along with the western part). Because of this location well, PGM-52 was also believed to be less affected by pressure drawdown as to the rest of the wells in the field.

In those 34 months, the overall pressure drawdown in well PGM-52 was 3.96 bar, giving a drawdown rate of about 1.41 bar per year (Figure 4).

4. RESERVOIR RESPONSE TO EXPLOITATION

Figure 4 shows the declining trends measured in some wells around the field by the different downhole pressure gathering units installed. The reservoir pressure has declined continuously with time, where the most affected zones near the wells PGM-47, 11 and 42 show a pressure drop in the order of about 2.0 bars-a per year (Moya and Castro, 2004). The north and central zones are the most affected by exploitation. The wellhead pressure in most of the wells has dropped by 1 to 3 bars-a, due to the reservoir changes previously discussed. An exception is well PGM-10, where the wellhead pressure increased with time.

A good correlation between the reservoir pressure decline and the commissioning of each power plant is observed, where an increase in pressure drop is observed for an increase in mass extraction. Moreover, an immediate recovery in reservoir pressure is observed when the mass extraction was decreased during maintenance of the different power plants (Figure 4). This clearly indicates the hydraulic connection between the wells located in the central-western part of the field. These short periods of maintenance have also produced in some cases an increase in the reservoir pressure. However, this recovery has not been high enough to compensate the total pressure decline observed during the entire Miravalles production history (Castro, 2001).

There is also some connection between the injection and production sectors of the field. The main effect has been positive, as the injection fluids provided pressure support in the reservoir. This effect is mainly related with the injection zone located at the western part of the field (PGM-22 and PGM-24) and its relationship with the north and central parts (where the majority of production wells are located). Injection in the southern part of the field has reflected some minor thermal breakthrough in the closer production wells (specially well PGM-12). Results of the numerical modeling using TOUGH2 has recommended to maintain the injection load to the western part of the field (GeothermEx, 2002) for providing pressure support to the central part of the field.

5. RESERVOIR MODELING APPROACH

Lumped parameter modeling is a simple method where the reservoir is modeled in different parts, each of them having some distinct hydrological properties. Those properties are lumped together, simplifying the reservoir characteristics into a few dependent variables (Axelsson and Arason, 1992). The method visualizes the reservoir as a network of separate tanks and resistors, each of them representing different parts of the reservoir (tanks) and permeabilities (resistors). This network can be open or closed to a constant pressure boundary (Axelsson, 1989). An automated, least squares inversion program, LUMPFIT, is available for solving the parameters that define the lumped models that would fit the observed pressure and production history of the reservoir (Arason and Björnsson, 1994).

Simulations were carried out in wells PGM-09, PGM-14, PGM-29 and PGM-52. Since PGM-09 has the most complete pressure drawdown history (about ten years from October 1993 to August 2003), its corresponding model provides more confidence than the rest of the models.

These simulations were carried out using either a single closed or a single open tank models, for each of the different cases. In some cases a two tank closed model could be obtained, but gave physically impossible solutions. The available set of historical data for the monitoring wells were used in the simulation runs and only in one case where only the late time data of PGM-09 was used to observe the pressure response after the commissioning of Unit III. Steam flows were used in the modeling process since all the separated brine in Miravalles is injected back to the reservoir. Also, an initial simulation run for PGM-09 using the total massflow was made.

5.1 PGM-09

A satisfactory match between the observed and calculated pressures behavior was obtained using an open tank model, giving a determination coefficient of about 99%. The modeling results are presented in Figure 5 including the future reservoir response estimated by the model.

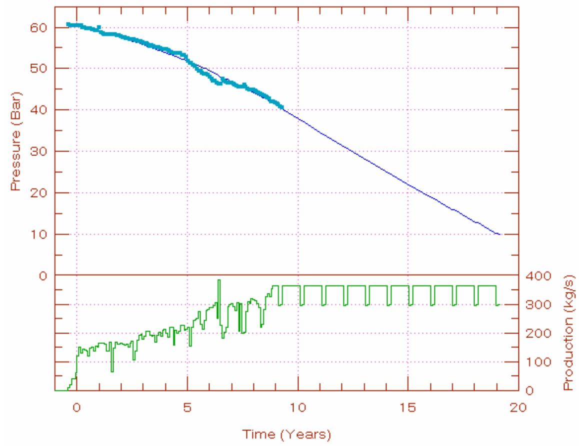

Figure 5: Matching and Prediction of the Future Reservoir Pressure (PGM-09) – Steamflow Rate.

There is also a continuous pressure drawdown observed under the actual exploitation regime over the 10-year simulation period. The overall pressure drawdown is 25 bar or 2.50 bar per year.

The model produced a continuous pressure drawdown under the actual exploitation regime (about 2000 kg/s of total mass and about 350 kg/s of steam flow) over the 10-year simulation period. The overall pressure drawdown is 30.6 bar or 3.05 bar per year.

A model using the total massflow rates was also made, and the results presented in Figure 6. The model gave similar results compared with the model using steamflow rates, so it was decided to employ the steamflow rate data in the succeeding simulation runs because it represents more the exploitation conditions in Miravalles.

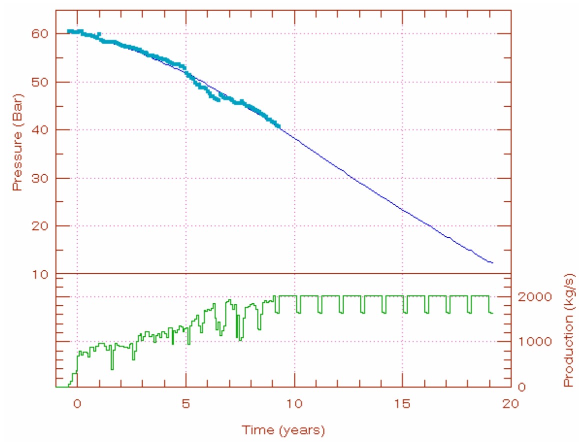

Figure 6: Matching and Prediction of the Future Reservoir Pressure (PGM-09) – Total Massflow Rate.

A model using only the late-time data of the pressure history was also made, and the results presented in Figure 7. This model was made for evaluating the observed change in the pressure response after the Unit III commissioning.

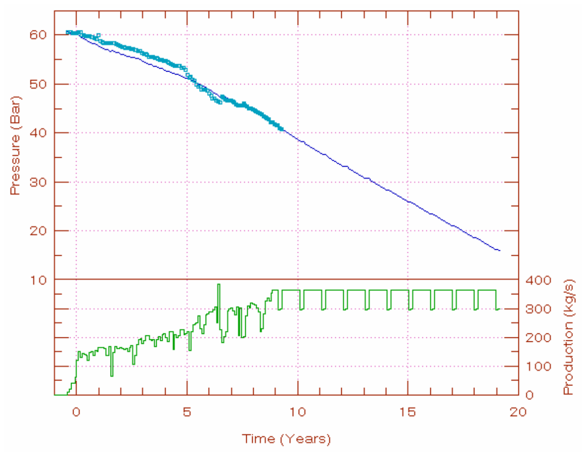

Figure 7: Matching and Prediction of the Future Reservoir Pressure (PGM-09 Late-time Data) – Total Massflow Rate.

5.2 PGM-14

A good match between the observed and calculated pressures could not be obtained in this well, having only a closed tank model with a determination coefficient of about 45%. The pressure drawdown history was very short; which also influence the confidence level of the model. This can be observed in Figure 8. For this reason, the future reservoir response estimated using the model was not made.

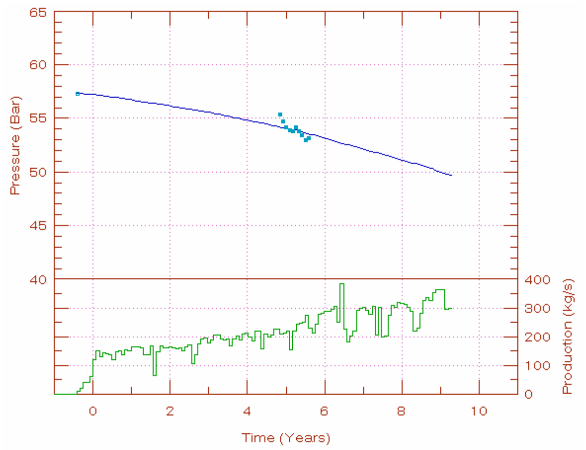

Figure 8: Matching of the Reservoir Pressure (PGM-14).

5.3 PGM-29

A match between the observed and calculated pressures was obtained by using an open tank model, giving a determination coefficient of about 89%. The determination coefficient of this model is not as good as the model using well PGM-09. This can be observed in Figure 9, including the future reservoir response estimated by the model.

A continuous pressure drawdown is obtained under the actual exploitation regime over the simulation period. The overall pressure drawdown is 46 bar or 3.63 bar per year. The negative pressure in Figure 9 has no physical meaning, and only represents the pressure at the reference point (water level falls below the position of the monitoring probe where the pressure was measured).

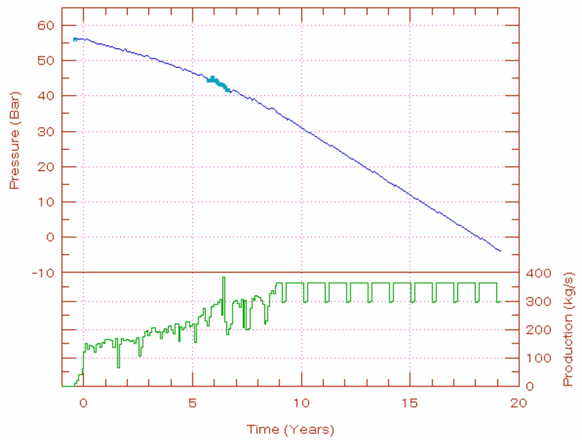

Figure 9: Matching and Prediction of the Future Reservoir Pressure (PGM-29).

5.4 PGM-52

A good match between the observed and calculated pressures was obtained using an open tank model, giving a determination coefficient of about 93%. This can be seen in Figure 10, together with the future reservoir response estimated by the model.

A continuous pressure drawdown is observed under the actual exploitation regime, followed by a stabilization over the simulation period. The overall pressure drawdown estimated over the first 9 years after the monitoring system was retired is 9.7 bar or 1.10 bar per year. After that, a 6-year period of simulation showed an overall pressure drawdown of 0.12 bar or 0.02 bar per year.

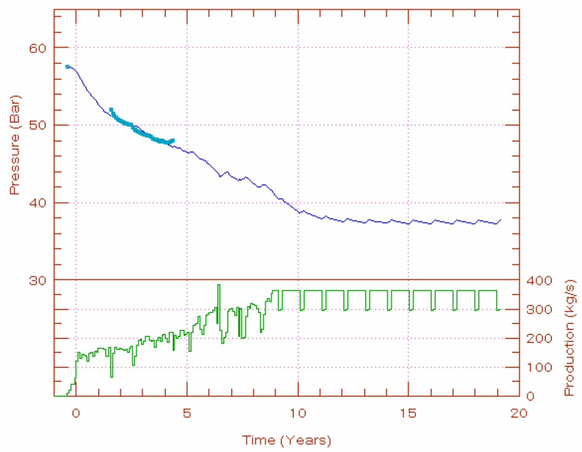

Figure 10: Matching and Prediction of the Future Reservoir Pressure (PGM-52).

6. DISCUSSION

The lumped parameter models presented suggest a rapid pressure drawdown in the production zones of the field, as shown in the results of PGM-09 and PGM-29 lumped models. Well PGM-09 is located at the central part of the field, which explains the fast pressure drawdown due to the intensive mass extraction in that zone. The zone where well PGM-29 is located seems to have a good connection with the rest of the reservoir, as it can be seen in the similar drawdown rates observed. The pressure drawdown predicted in these two wells is about 2.5-3.0 bar per year.

When only the last part of the pressure drawdown history is taken, it can be seen that the predicted future drawdown rate is slower than the pressure drawdown rate when the total production history is taken. This pressure drawdown rate is relatively close to the historical drawdown rate measured in well PGM-09.

The actual pressure drawdown observed has affected some wells of the northern part of the field (wells PGM-01, PGM-10 and PGM-63). These wells have lost part or totally its production. Calcite deposition in the formation fractures has also contributed to the decline in productivity of these wells. Most of the wells in Miravalles are chemically treated using calcite inhibitor that is injected inside the well. When the reservoir pressure declines, the flash point inside the wellbore also declines which may eventually reach the permeable zones or the formation. Under this condition, it would be then be very difficult to inhibit calcite deposition in the formation.

The lumped parameter model of well PGM-52 suggest a very slow pressure drawdown in the injection zones of the field, showing that injection has a positive impact over the pressure drawdown into the field. This is understandable, since the location of the well into the injection zone allows it to get a good pressure support because of the good amounts of injection water into that zone. This does not consider negative impacts like the thermal breakthrough that can be seen if too much injected waters return to the field, or if these waters return too fast.

The modeling parameters obtained for the whole models are shown in Table 1. If an average temperature of 235 ºC, a fluid density ρ of 820 kg/m3, a liquid compressibility C_w of 1.2x10-9 Pa-1, a total compressibility C_t of 5.6x10-10 Pa-1 (Acuña, 1990), a porosity Φ of 5-10% and a reservoir thickness of 1000 m are assumed (ICE/ELC, 1995), some calculations for estimating the reservoir volume and area can be made based on the parameters shown in Table 1. Equations for obtaining reservoir volume and area are discussed in Axelsson, 1989.

Table 2 shows the results obtained for these calculations. The proven reservoir Miravalles area based on the actual wellfield exploited is around 18-20 km^2 and at least around 8 km^2 can be easily considered as a probable expansion sector (at the east of wells PGM-02 and PGM-19, near well PGM-55). Compared this with the results showed in Table 2, the lumped models of PGM-14 and PGM-09 (whole and late data – steam) are in relatively good agreement. The zone at the east of the known field (around well PGM-55) has not been extensively investigated, but there are good possibilities for finding geothermal resources.

The lumped parameter modeling simulates the past history and provides predictions for the future pressure behavior of the field. It should be noted that this method does not consider some situations that will affect the reservoir behavior, like temperature changes or expansion of boiling zones into the reservoir due to massive exploitation. Also, the injection returns and the reservoir natural recharge would affect positively the pressure drawdown in the future.

Some expansion of the boiling in the reservoir at the north zone of the field has actually been noticed, probably caused by the pressure drop due to the exploitation regime. When the boiling become extended in more areas of the field it will lessen the pressure drawdown actually observed.

The temperature of the injected waters of the field recently changed because of the recent commissioning of Unit V, a binary-type power plant. Prior to this change, the waters were injected back to the reservoir at 165 ºC, but have now declined to 136 ºC. This temperature change can affect the future reservoir performance.

Numerical modeling studies conducted in 2001 have recommended the necessity to maintain a good injection load at the western part of the field, and the results also predicted a future lowering in the drawdown pressure observed (GeothermEx Inc., 2002). This can be explained by the rapid evolution of the northern part of the field. The loss in production of the wells (PGM-01, PGM-10 and PGM-63) in this part of the field has made it impossible to inject the recommended rates into well PGM-22, causing a lack in pressure support in that zone of the field. In addition, chemical effects into the reservoir (calcite deposition, etc.) cannot be numerically modeled by TOUGH2, which could greatly affect the reservoir behavior in Miravalles (Sánchez et al, 2005).

Performing new injection schemes that will lead to improvement in pressure support of the field without affecting the temperature of the reservoir fluids is an obligatory task to be done in the near future. One of the possible actions to be taken is to inject small quantities of separated waters (165 ºC) into the north zone of the field. It is also necessary to continue and strengthen the monitoring of reservoir pressure in order to determine if the injection returns will reduce the pressure drawdown behavior in the future. Monitoring of the pressure response would also establish possible acceleration of the temperature decline into the field.

The same modeling study (GeothermEx, Inc., 2002) has also recommended to decrease the mass extraction in the central part of the field, by moving the 5 MWe back pressure unit to well PGM-29. This action will reduce the negative impacts over this part of the field.

Table 1: Best-Fit Reservoir Parameters.

	WELLS					
	PGM-09			PGM-14	PGM-29	PGM-52
PARAMETERS	**1 Open Tank Whole Data Steam Mass**	**1 Open Tank Whole Data Total Mass**	**2 Closed Tanks Late Data Steam Mass**	**1 Open Tank Whole Data Steam Mass**	**1 Open Tank Whole Data Steam Mass**	**1 Open Tank Whole Data Steam Mass**
A	2.88100x10^{-5}	5.00828x10^{-6}	5.54931x10^{-5}		2.95772x10-5	1.31097x10^{-4}
L	4.58082x10^{-5}	5.48481x10^{-5}	3.25437x10^{-3}		8.35040x10^{-9}	2.29951x10^{-3}
B	0	0	1.92064x10^{-5}	1.01849x10-5	0	0
κ_1	76223.5	438474	29397.8	215612	74246.4	16750.9
κ_2		1.09515x10^{-4}	84938.9			
σ_1	1.590014x10^{-5}		3.23645x10^{-4}		2.82326x10^{-9}	1.75405x10^{-4}
Det. Coef.	98.688	98.788	98.390	45.194	89.446	93.372

Table 2 Reservoir Volume and Area Estimations.

	Reservoir Volume (km^3) – Confined System			Reservoir Area (km^2) – Free Surface		
WELLS	**1 Open Tank Whole Data Steam Mass**	**1 Open Tank Whole Data Total Mass**	**2 Closed Tanks Late Data Steam Mass**	**1 Open Tank Whole Data Steam Mass**	**1 Open Tank Whole Data Total Mass**	**1 Open Tank Late Data Steam Mass**
PGM-09	166 – 332	955 – 1910	249 – 498	7.5 – 15	43 – 86	11 – 22
PGM-14	470 – 940	NA	NA	21 – 42	NA	NA
PGM-29	162 – 323	NA	NA	7 – 15	NA	NA
PGM-52	36 – 73	NA	NA	2 – 3	NA	NA

7. CONCLUSIONS

The results of the lumped parameters models discussed in this paper are in good agreement with the pressure drawdown observed in the Miravalles Geothermal Field up to date.

The models presented in the last section suggest a rapid pressure drawdown in the production zones of the field, as shown in the results of PGM-09 and PGM-29 lumped parameter models. The pressure drawdown predicted is about 2.5-3.0 bar per year.

The lumped parameter model of well PGM-52 suggest a slow pressure drawdown in the injection zones of the field, showing that injection has a positive impact over the pressure drawdown into the field. This does not consider negative impacts like a possible thermal breakthrough due to heavy or fast-injected waters return.

The accuracy and results of the lumped parameter modeling can be limited for some situations that will affect the reservoir behavior, like temperature changes or expansion of boiling zones into the reservoir due to massive exploitation. Some of this condition has been actually noticed (expansion of the boiling in the reservoir at the north zone of the field and the temperature of the injected waters of the field changed from 165 ºC to 136 ºC).

Even though the forecasted behavior obtained for the different lumped parameters models is very pessimistic due to the continuous pressure drawdown simulated, this is a warning signal in order to implement some actions for minimizing this problem.

Actions must be taken for slowing the pressure decline observed in the field. Some of these actions include new injection schemes in order to improve the pressure support of the field without affecting the temperature of the reservoir fluids. Other action includes the transfer of the 5 MWe back pressure unit from the central part of the field to well PGM-29. The injection of small quantities of separated waters (165 ºC) into the north zone of the field is also considered, but intensive temperature and pressure monitoring is highly advisable if a possible acceleration of the temperature decline into this zone of the field is observed.

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