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REINJECTION EXPERIENCES IN THE CERRO PRIETO GEOTHERMAL FIELD

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ABSTRACT

This work presents a general review of the development of the reinjection project at the Cerro Prieto Geothermal Field begun in 1986. The project has proven an overall reinjection capacity of 81% of all water produced, and to date an average reinjection rate of 2996 ton/hr -- 45% of the annual volume of water produced -- has been reached.

Even though more than 67.6 million tons of brine have been reinjected, most of it at an average temperature of 26°C, the field's productive capacity has shown no significant deterioration. Based on the chemical and thermal results monitored in the reservoir, plans have been made to continue this project until the reinjection of 100% of all residual brine produced is achieved.

INTRODUCTION

For more than twenty years the Cerro Prieto Geothermal Field (CPGF) has been producing the steam necessary for commercial electricity generation. Currently the Cerro Prieto field generates approximately 72% of the total power consumed in the northwestern Mexican state of Baja California. The Comisión Federal de Electricidad (Federal Electricity Commission: CFE) is in charge of developing and operating the geothermal field and its three power plants.

As one of the largest liquid-dominated systems in the world, Cerro Prieto produces an average of 6,600 ton/hr of separated brine from the more than 120 productive wells currently connected to the steam-gathering system. After being discharged from the separators, this brine is transported to an evaporation pond by an open-channel surface system.

Before 1986 average brine production was only 1450 ton/hr, because only the CPU power plant (180 MW) was in operation. The increase to the present rate of 6,600 ton/hr occurred in 1986, when the CPD and CPT power plants (220 MW each) were put into operation. At that time, the disposal of such large quantities of brine -- containing an average of 927.0 ppm of silica (SiO_2) became a serious problem.

The solar evaporation pond was constructed on the field's west side and periodic enlargements have brought it to its current surface area of 19 Km2. Since the brine contains some dissolved useful salts (Table No.1), the pond's original area, form and average depth of 2.0 m (1.5 m at present) were designed to allow oversaturation of the brine and recovery of part of these salts. Although this recovery project was suspended due to economic constraints, the CFE is currently seeking private investors to allow recovery to be restarted.

Table No.1

Average Concentrations of Principal Components in CPGF Brine [ppm]

Comp.	CPU	CPD	CPT	Tot. Avg.
Na	7,508	9,581	8,326	8,510
K	1,536	2,397	1,953	1,971
Ca	410	420	304	388
Cl-	13,781	17,651	15,256	15,638
SiO_2	791	1,034	963	927
TDS	25,162	31,809	27,415	28,286

Although the region's evaporation rate increases in summer to 7.1 mm/day, producing an average seasonal rate of 4230 m^3/hr, during past winters it was necessary to release excess brine outside of the system when production rates increased beyond the pond's storage capacity.

At this point the CFE started an aggressive internal disposal campaign, with reinjection as its top-priority solution.

WELL TESTING

As a first step, an intensive program for testing non-productive wells was created in 1986. This program was designed to determine the injection capability of each available well, using this data to establish a base level for the reinjection project.

At that time some injection data was already available as a result of a series of transient injectivity tests performed in 1984 and 1985 to estimate the field's hydraulic recharge potential. Nevertheless, as brine disposal became the main concern, it was necessary to design a different type of well test in order to perform this first step with a minimum of required time, equipment and personnel.

The methodology for these new tests basically consisted of using a quick pipe and hose installation as shown in Figure No.1.

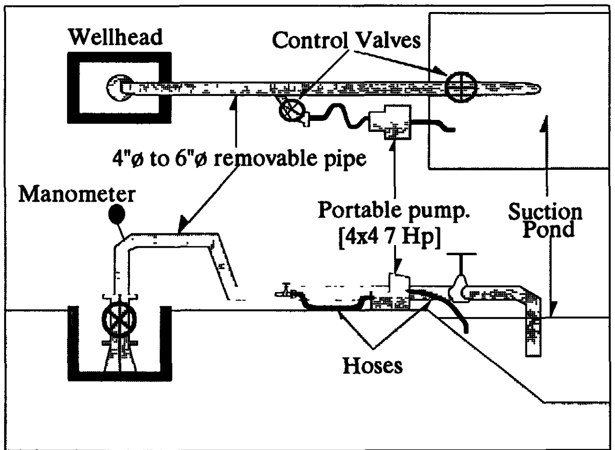


Figure No. 1 – Typical injection well testing arrange.

This system was designed to produce vacuum wellhead pressures, pumping from the suction pond and forcibly deepening the water level inside the well. Once this occurs, the control valves are used to keep the system working by itself as a "siphon". At this point a series of wellhead pressures and injection flow rates can be easily measured using standard equipment (in this case, an ultrasonic flowmeter). Whenever necessary, an air drain can be performed before the siphoning stage, by opening a drain valve located at the manometer fitting and increasing the flow rate to the maximum allowed.

If it is impossible to produce vacuum wellhead pressures, a bigger pump is installed in the same system and the same measurements are taken. In this case, the objective is to determine what size and type of pumping equipment is necessary, since the well cannot be used for reinjection with a gravity-motion (siphon) system alone.

All non-productive wells were tested using the above methodology. In this way ten wells were identified as being cost-effective for use as reinjection wells. These wells and their locations are shown in Figure No. 2 and Table No. 2.

Figure No. 2.

Injection Wells location map

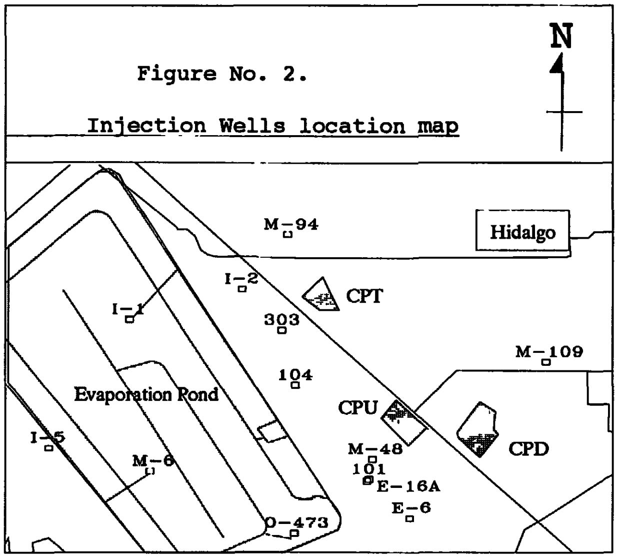


Table No. 2
Injection Wells description

Well	Completion			
	ø (in)	Depth (m) from	Depth (m) to	Type
0-473	4 ½	1981	2252	Sloted
M-6	11 3/4	535	741	Sloted
E-6	7	2289	2567	Sloted
101	6	1209	1361	Open hole
M-48	7 5/8	1245	1393	Sloted
104	8 ½	1310	1595	Open hole
E-16A	4 ½	1392	1592	Sloted
M-109	7	2098	2395	Sloted
M-94	5	2196	2328	Sloted
303	9 5/8	1006	1324	Sloted

PROJECT DEVELOPMENT

While the systems for locating and testing injection wells were being developed, it was decided that continuous injection should be begun along the field's southwest edge. This was due to its large number of existing wells outside the production zones, as well as its proximity to the evaporation pond (Figure No. 2). So well 0-473 was placed in operation as the first permanent injection well in June of 1989, using a "siphon" system to achieve an average initial injection rate of 284 ton/hr.

Since that time the project has undergone continuous growth through the addition of the permanent injection wells shown in Table No.3.

The permanent siphon injection systems installed are similar to those shown in Figure No. 1, and operate as described. They differ only in the use of pipes with a diameter of 10"ø-16"ø, instead of the original 4"ø-6"ø pipes which are removed and installed in the next well to be tested.

Table No. 3

Permanent Injection Wells Added [89-90]			
Well	Start-up date	Flowrate Avg(T/h)	System Type
O-473	June 1989	284.3	"Siphon"
M-6	October 1989	38.8	"Siphon"
E-6	October 1990	358.4	"Siphon"
303	October 1990	530.2	"Siphon"

As a special case, well 303 was tested as the first injection well completed within the production area to the north of the CPU field (Figure No. 2). The goal of this test was to determine the feasibility of its use as an injection well during the winter season (minimum evaporation and electricity demand) and as a production well during the summer months (maximum evaporation and electricity demand). Towards this end, continuous injection was maintained from October, 1990 through April, 1991. A total volume of 3,096,487 tons of brine was injected at an average rate of 689 ton/hr.
No negative impact on the productivity of neighboring wells (monitored in this respect) was detected. After this period of injection, well 303 was stimulated and brought back into production; but it did not reach the pressure levels necessary to be integrated into the generating system.
For this reason, it currently continues to be used as a backup injection well when measurements of the evaporation pond levels show it to be necessary.

The injection wells O-473 and M-6 were tested from May 1991 onwards with injection pumping systems which raised their wellhead pressures to 100 psi through the use of 100 HP centrifugal pumps (one per well). This increased the M-6 injection rates from 55 ton/hr (by siphoning, during 1990) to 176 ton/hr, which led to its establishment as the first permanent pumped reinjection well.

The experience gained during the injection in well 303 was utilized to establish a large-flowrate experimental reinjection program in the productive strata to the north and south of the CPU field.
This was done in order to take field measurements of the actual reservoir response to cold water injection, and to compare this to previous theoretical studies. This new program was started in 1992, with injection in the wells listed in Table No. 4. As part of this program, an intensive campaign of geochemical and production monitoring of the production wells neighboring each of the injection wells was undertaken. The measurements produced by this monitoring will be discussed later.

In all of the above activities untreated residual brine, at ambient temperatures (26°C on the average), was used as the injection fluid. Nevertheless, efforts were made leave the brine as long as possible both in the evaporation pond and on its final trip

Table No. 4

Injection Wells in Productive Zones of CP				
Well	Zone	Start-up date	Avg.Rate (ton/hr)	System Type
104	CPU-N	1/06/92	544.5	siphon
M-48	CPU-S	1/21/92	566.5	siphon
101	CPU-S	1/22/92	813.2	siphon
E-16A*	CPU-S	5/11/92	125.6	hot-brine
M-109**	CPT	5/24/93	92.7	hot-brine

* Directly from the well E-61 separator
** Directly from the well E-41 separator

through the canal system to its final destination in the suction point of each well. Resulting natural deposition increases concentrations of chlorides, but markedly decreases those of silica. For this reason, to date no scaling problems have been detected in any of the injectino wells. The final brine concentrations at their injection points are shown in Table No. 5.

The hot brine reinjection systems E-61→ E-16A and E-41→M-109 were also included in this project (see Tables No. 4 and No. 5).
In both cases the separation pressure of the production wells (E-41 and E-61) was used to move the brine directly to the wellhead of the injection wells (E-16A and M-109).

Table No. 5

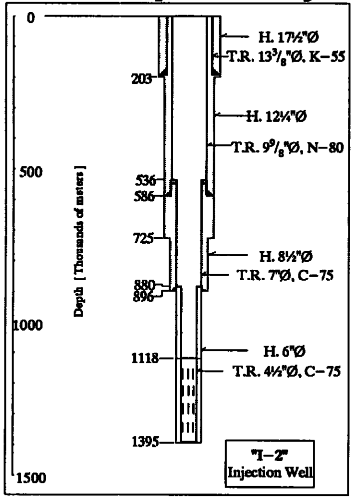
Chemical Components of the Injected Brine				
Well	(PPM)			
	SiO_2	Cl-	Na	K
O-473	116	17,789	9,949	2,167
M-6	118	18,515	10,308	2,333
E-6	102	22,508	12,282	2,800
303	106	27,228	14,984	3,429
104	106	55,966	29,860	7,429
M-48	104	23,234	12,462	2,857
101	104	23,234	12,462	2,857
E-16A	780	7,987	4,436	827
M-109	760	7,261	4,256	777

Even though low-temperature reinjection into the CPU productive strata did not cause any significant negative impact, the observations to be discussed below suggested the advisability of moving the injection sites towards the edge of the field, away from its productive zones.
Because of this and previous experience, in 1992 drilling was also begun on well I-2.
This well was designed for use as a permanent injection well. It came into operation in November of 1992, using a siphon injection system to achieve an initial average rate of 243 ton/hr.

Meanwhile, well 101 was permanently shut down on June 26, 1992 following a gradual reduction in its injection rate. This policy continued in 1993: A second permanent injection well (I-1) was drilled and came into operation in January, using a pump system to achieve an average injection rate of 578 ton/hr; while well M-48 was permanently shut down in April. In order to reinject as much brine as possible, permanent injection was also begun into well M-94 in November of 1993. This well's pumping system allowed an initial rate of 353 ton/hr.

The design used for the injection wells I-1 and I-2 is quite similar to that of normal production wells (Figure No. 3). Criteria were applied to finish them in intervals which combine fracturing with the highest possible percentage of sandstones. This allowed a total volume of 67,629,598 tons of brine to be reinjected by April of 1994, as shown in Figure No. 4 and in agreement with the total cumulative rates shown in Figure No. 5.

Figure No.3.- I-2 Completion Diagram



In summary, at this point Cerro Prieto has a proven injection capacity of 5,361 ton/hr (81.2% of all produced brine). Even though 35.9% of this capacity (1,923 ton/hr) has had to be sacrificed, in 1993 45.4% of all brine produced (2,996 ton/hr) was reinjected (Figure No.5), with no significant effects on production.

The current results of this reinjection project can be summarized by the information in Table No. 6.

Figure No.4

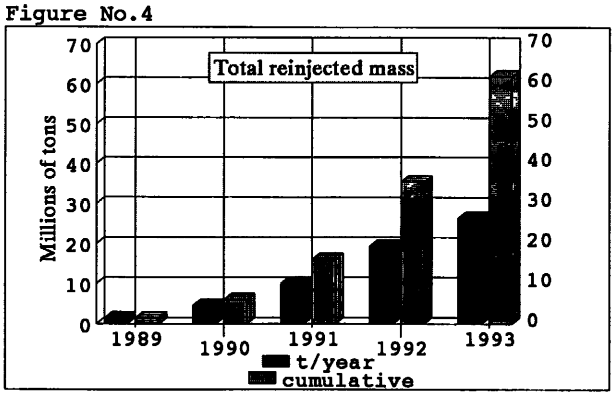


Figure No. 5.

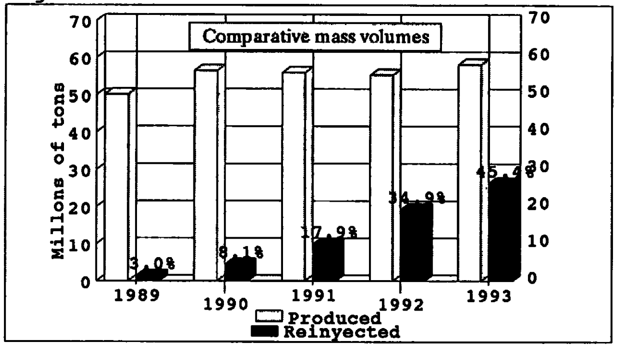


Table No. 6

Current reinjection well situation				
Well	Flowrates (ton/hr)		System	Current
	maximum	actual	Type	Status
O-473	287.0	266.0	Siphon	Injecting
M-6	176.0	37.2	Pumping	Injecting
E-6	692.0	692.0	Siphon	Injecting
303	689.0	209.0	Siphon	Back-up *
104	544.0	0.0	Siphon	Available
M-48	566.0	0.0	Siphon	Available
101	813.0	0.0	Siphon	Available
I-2	372.0	318.0	Siphon	Injecting
E-16A	126.0	90.6	hot bne.	Injecting
I-1	650.0	650.0	Pumping	Injecting
M-109	93.0	77.0	hot bne.	Injecting
M-94	353.0	131.0	Pumping	Injecting
I-5**	??	??	??	Testing
Totals	5361.0	2470.8		

* Injection in winter only
** Under testing

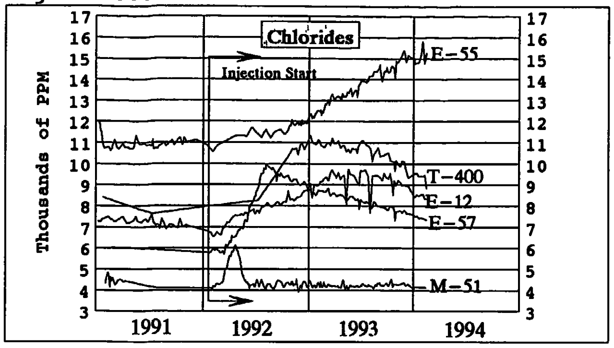
OBSERVED EFFECTS

Monitoring of the CPU reservoir's response to injection developed out of geochemical sample analyses together with normal productivity and thermal measurements in wells neighboring each injection well.

Chlorides (Cl-) were chosen as the natural chemical tracers for tracking injected fluids. This was because their chemical stability for these purposes had been proven in other fields (Harper and Jordan, 1985; Bodvarsson et al, 1988), and because of the difference between the concentrations measured in the aquifer (4,000 to 9,000 ppm) and in injection brines (Table No. 5).

As expected, the first reaction shown by the monitored wells was a marked increase in chloride concentrations in the produced water (Figure No. 6). Consistencies between dates of concentration changes and the beginning or variations of injection rates (Figure No. 7) left little room for the possibility that these chloride increases might be the result of some natural phenomenon other than the arrival of the injection front (such as local boiling or natural fluid outbreaks from deeper strata).

Figure No.6.



The average speeds of spread for the injection fronts, as shown in Table No. 7, are estimated on the basis of how much time passes between the start of injection and the first abnormal increase in chlorides in each monitored well.

Furthermore, considering chloride concentrations grow in proportion to the speed of the injection fluid's spread, it was also possible to estimate the behavior of the specific speeds of the injection fronts between each monitored production well and its neighboring injection well. These calculations showed speeds of spread of between 42 and 18 m/day during the first 15 days of injection, potentially decreasing to between 0.9 and .3 m/day up to 360 days after injection began.

Figure No.7.

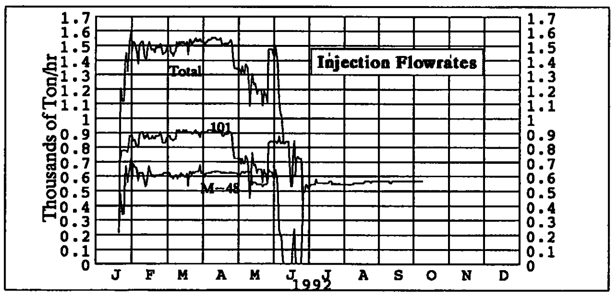
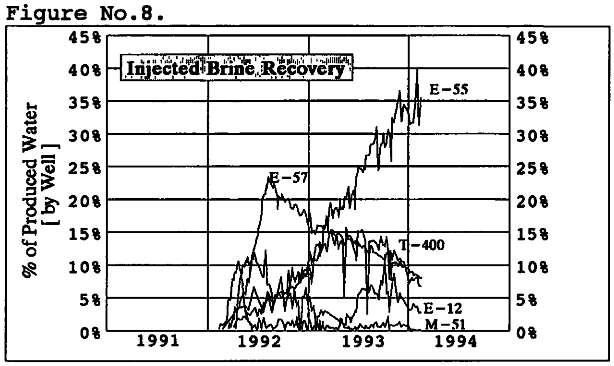


Table No. 7

Average speeds of spread				
Wells			Arrival	Average
Injector	Producer	distance (m)	time (days)	velocity (m/day)
M-48	E-10	259.5	55	4.72
101	E-12	258.7	42	6.16
M-48	E-57	98.5	60	1.64
101	M-51	275.7	37	7.45
101	M-73	510.0	37	13.78

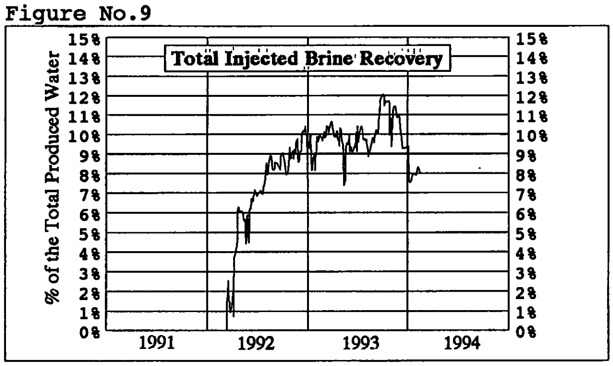
By applying the procedure suggested in the reference (1) it was possible to determine the recovery percentages for selected wells shown in Figure No. 8. It should be noted that the behavior of this recovery is irregular, and different for each well. Particularly noteworthy are the figurės for well M-51 and E-55, showing recovery rates of 10% and 35% and later tendencies to stabilize and increase, respectively.

Figure No.8.



By extending this analysis to all the chemically affected wells in the southern zone, it was possible to also estimate that on the average, 9.5% of the total mass injected in the zone was recovered in production wells, with a maximum of 12% reached in September of 1993 (Figure No.9).

Figure No.9



It should be pointed out that the rate variations shown in Figure No. 7 are due to work operations carried out on the surface. For this reason, it is considered that to date the receptive capacity of these formations for injected fluid has not been affected.

On the average, 20 days after the above chemical changes were detected the monitored production wells demonstrated an overall loss of wellhead pressure (Figure No.10). Furthermore, during the following 15 days production trends were detected which basically consisted of a marked increase in the production of separated water, with a consequent decrease in production enthalpy (Figure No.11).

During this process steam production continued without any changes in its specific behavior. Only in a few cases did it decrease slightly during an average period of 60 days after variations in water and enthalpy production had been noticed. This could be due to the fact that total steam and water permeabilities remain constant in spite of the great impact which reinjection can have on the system's total mobility (Bodvarsson, 1989).

Figure No. 10

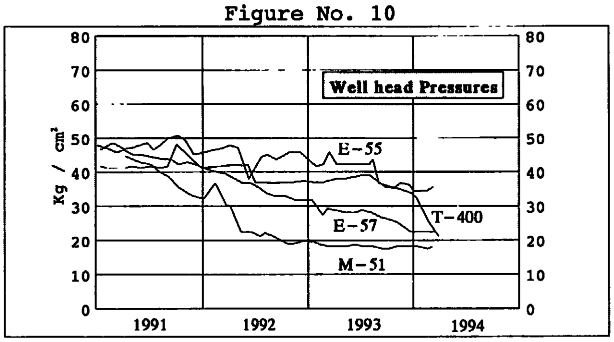
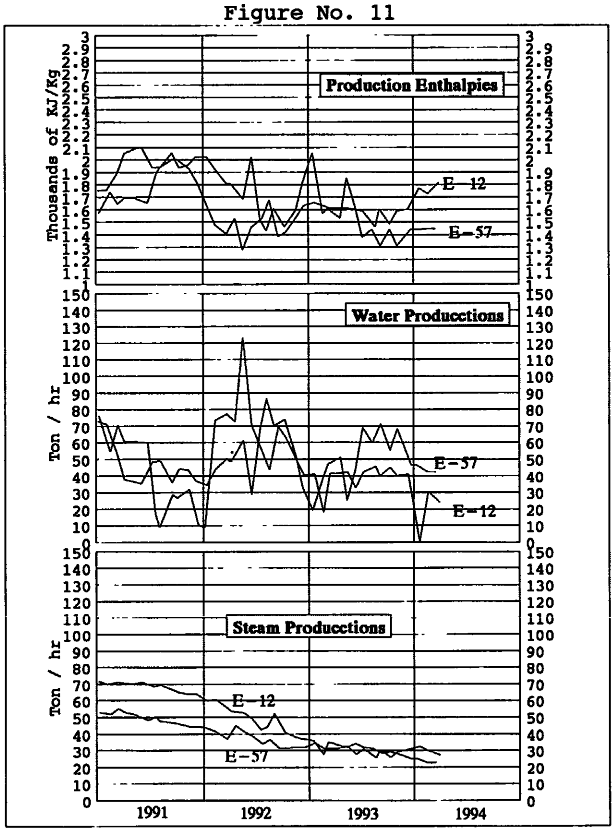


Figure No. 11



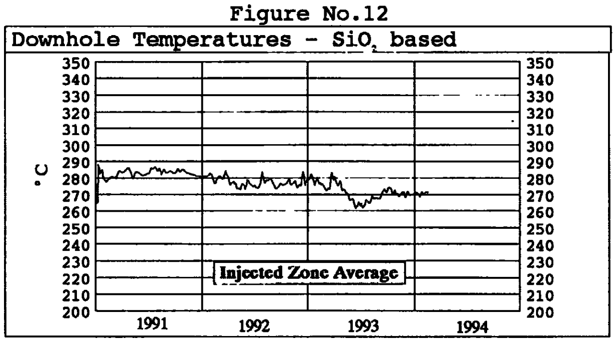
In addition to the effects mentioned, some wells also showed regular drops in downhole temperatures as measured by geothermometers, as well as drops in localized boiling wherever these had been detected.

Although some wells showed all these reactions, the overall production necessary to generate electricity was not significantly affected. There were even some wells where steam production showed no variations at all from their earlier performance. This was the case in wells E-12 and E-57.

The drops in steam production seen in some wells could well have indicated the start of a severe thermal decline leading to enthalpies below those of the saturated liquid under the original reservoir conditions (Bodvarsson, 1988). However, this behavior was not seen in any of the wells which had shown a drop in enthalpy.

Due to the impossibility of mechanically recording direct measurements (Kuster) in wells integrated into the generating system, it was necessary to estimate the behavior of downhole temperatures by using geothermometers as shown in Figure No.12. Here we can see an average overall cooling of 0.57°C/month in the zone affected by injection fluid.

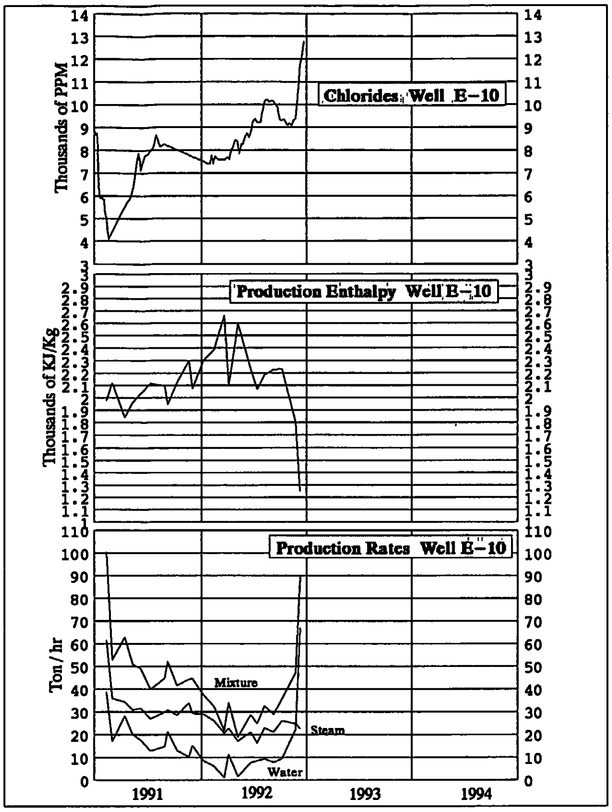
Figure No.12



In general, it seems clear in each case that the drops in wellhead pressures (Figure No.11) are a direct consequence of increased production of separated water (Figure No.11). This is due to the fact that greater water flow rate increases the specific weight of the fluid column which downhole pressure must displace inside the well. Even if one supposes that injection has increased reservoir pressures (Lippmann et al, 1977; Bodvarsson et al, 1985), it is to be expected that this possible increase would not be enough to maintain wellhead pressures due to the drag of cold water. Such was the case for wells E-12 and E-57, where the greatest drops in wellhead pressure corresponded to the greatest increase in separated water production (Figure No.11).

The case of well E-10 is also significant. After maintaining normal, trouble-free production, it showed a sudden increase in water production and a marked decrease in production enthalpy. It stopped flowing less than three months later (Figure No.13). Since this was the only seriously negative event which had resulted from injection, its behavior was analyzed using a well/reservoir simulator. The simulator showed that its death was due to the interruption of its productive dynamics through a strong rise in its flashing depth. This validated the phenomenon described in our previous paragraph since, additionally, this well never demonstrated any drop in steam production which would have indicated the influence of a severe thermal deterioration.

Figure No.13.



FUTURE EXPECTATIONS

Based on the experiences described here, there are plans to continue the expansion of the project until 100% of all residual brine is reinjected. The volume of this brine will depend on both the growth of production rates and on the specific characteristics of any mineral recovery project that is established.

Injection well construction has continued. Well I-5 has been completed and is now in the final testing stage; wells I-3, I-4 and I-6 are still in the design stage.

It is expected that additional well drilling will take place mostly in the regions surrounding the northern and southwestern parts of the field.

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