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NUMERICAL SIMULATION FOR CYCLIC STEAM INJECTION AT SANTA CLARA FIELD

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This article presents the methodology used and the results obtained in the construction, match and prediction of the first thermal composition simulation model done in Colombia by employing advanced thermal process commercial software, globally recognized because of its effectiveness in modeling these types of processes (CMG-STARS, 2005). The Santa Clara and Palermo fields were modeled and an excellent history match was achieved. All in all 28 wells and 17 years of production were matched.

Two production scenes were proposed. The first involved primary production from existing wells, in other words: primary production; and a second escen where all the wells in the field are converted into injectors and producers, to simulate cyclic steam injection. This injection process included a series of sensitivity studies for several of the parameters involved in this technology, such as: pressure and temperature injection, time and rate of injection, heat injected, soaking period, steam quality, and injection cycles. This sensitivity study was focused on optimizing the processes to obtain the maximum end recovery possible.

The information entered into the simulator was validated by laboratory tests developed at the Instituto Colombiano del Petróleo (ICP). Among the tests performed the following were assessed: rock compressibility, relative permeability curve behavior at different temperatures, formation sensitivity to injection fluids, DRX analysis and residual saturation of crude oil for steam injection. The aforementioned results are documented in this paper.

Keywords: *cyclic steam injection, Santa Clara field, numerical simulation, sensitivity analysis, laboratory test.*

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Este artículo presenta la metodología empleada y los resultados obtenidos de la construcción, ajuste y predicción del primer modelo de simulación composicional térmica hecho en el país, mediante el uso de un software comercial de procesos térmicos avanzados, el cual es reconocido a nivel mundial como la herramienta de mayor uso y efectividad en el modelamiento de este tipo de procesos (CMG, 2005). Los campos Santa Clara y Palermo fueron los modelados y el ajuste histórico logrado fue excelente, la producción de fluidos del campo ajustó en un 100% y para los pozos en un 97%. En total se ajustaron 28 pozos y 17 años de producción.

Se plantearon dos escenarios de producción. El primero de ellos en producción primaria de los pozos existentes; es decir: declinación normal del campo, y un segundo escenario en que todos los pozos del campo son convertidos en inyectores y productores, para simular un proceso de inyección cíclica de vapor. Este proceso de inyección incluyó una serie de sensibilidades de varios parámetros involucrados en esta tecnología como fueron: presión y temperatura de inyección, tiempo y tasa de inyección, calor inyectado, período de remojo, calidad del vapor, y ciclos de inyección. Esta sensibilización tuvo como fin la optimización del proceso para la obtención del máximo recobro final.

La información ingresada al simulador fue validada con pruebas de laboratorio desarrolladas en el Instituto Colombiano del Petróleo (ICP). Entre las pruebas realizadas se evaluaron: compresibilidad de la roca, comportamiento de las curvas de permeabilidad relativa a diferentes temperaturas, sensibilidad de la formación a los fluidos de inyección, análisis DRX y saturación residual de crudo a la inyección de vapor. Cuyos resultados fueron documentados en este artículo.

Palabras Clave: *Inyección cíclica de vapor, campo Santa Clara, simulación numérica, análisis de sensibilidad, pruebas de laboratorio.*

INTRODUCTION

During prior years, Ecopetrol S.A. developed a study of feasibility and selection of recovery methods for the fields at the Southern Regional Management (Saavedra, 2003), in order to identify the most technically convenient and economically feasible methods to be implemented at these fields. According to crude oil characteristics for the Santa Clara and Palermo fields, the methods selected were cyclic injection, continuous steam injection and polymer injection. Later studies showed steam injection as the best alternative to increase the recovery factor at Santa Clara field. These studies were supported by results obtained from analytical simulations and consulting from international consultants (Farouq, 2003).

The recovery factor for the Santa Clara field in the year 2005 was 9%, a very low recovery rate. Thus the technological challenge to implement new technologies to increase production to profitable levels and incorporate new proven reserves into the national market. Heavy crude oil fields are currently considered one of the most viable alternatives to fill the large national demand for fuel. It is there that the methods of improved recovery, such as cyclic steam injection become more important, since they are the most successful thermal recovery techniques and the most applicable worldwide (Prats, 1986). Thus in Colombia several fields are being steam injected in this way, namely Jazmín, Teca and Nare fields with very positive results.

This process injects steam into the reservoir, which transfers the heat to the original fluids and to the rock, creating a warming of the area which causes a reduction of oil viscosity, allowing it to flow towards the well and later to the surface. The process is comprised of three stages:

The injection stage: during this stage heat is supplied as steam to the producing formation, for several days or weeks according to the estimated requirements. The objective is to reduce crude oil viscosity surrounding the well, up to a determined distance. The time employed depends on the quantity of steam injected and the capacity of the equipment used in the project.

Soaking stage: after the injection period, the well is closed off to establish a homogenization of the heated area around the well.

Production stage: at this time, the well is opened and it begins to produce a great quantity of water at high temperature resulting from the condensation of the steam injected. The water production rate will begin diminishing little by little, while crude oil production increases. For this reason the response of the well to stimulation depends principally on the viscosity of the oil, the existing permeability, the radius heated, the initial reservoir pressure and heat losses.

The duration of this stimulation effect (cycle) depends mainly on the speed with which the fluids produced cool off the formation and the rate of energy loss to the adjacent formations, both in a vertical as well as in the lateral direction. With time, these factors will cause a decrease in oil production for cycles to be performed, since a temperature drop increases oil viscosity, halting the process when the least economically feasible rate is reached.

STATIC MODEL

A static reservoir model (figure 1) was developed using modeling software, integrating a structural, petro-physical and facies model. The model is a “non-orthoghonal corner point” model with a total of 210,490 cells (35, 97, 62 in directions I, J, K, respectively).

The absolute permeability values presented in the grid where estimated by using three formulas which included porosity values, and they vary according to three different types of rock, which were previously interpreted by means of petro-physical studies. These values were entered into Petrel in a LAS format and used for populating cell properties in the geo-statistical model. It included a facies model, where population of properties was done by keeping in mind the analysis performed to scale units for this reason. Some of the properties obtained by interpolation of petro-physical parameters were overwritten by the figures obtained through the facies analysis. The interpolation of petro-physical values were generated foot by foot and then scaled to approximately 7 feet.

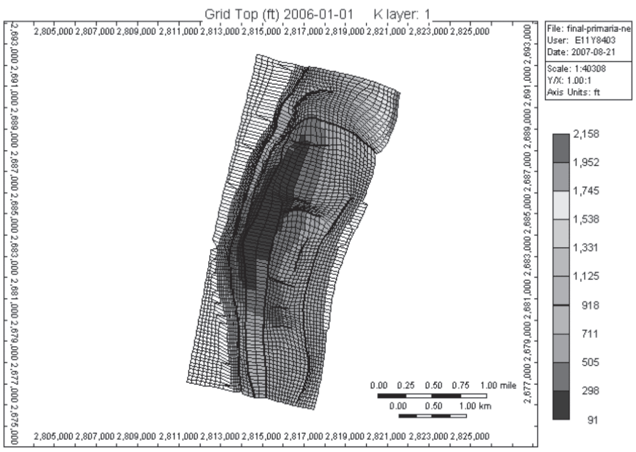

Figure 1. Static model for Santa Clara field

Geological description

Geologically the Santa Clara field is part of the Neiva subbasin, which encompasses part of the south basin of the Upper Magdalena Valley and corresponds to an elongated depression heading SW-NE, where there is a predominant system of bedding thrusts converging toward the East (Barrios *et al.,* 2003). The structure of the field is defined as an asymetric elongated anticlinal whose main direction is north to south, with pitching both in the South as well as in the North. The anticlinal is 5,5 km long and 2,7 km wide. Figure 2 shows the structural model for the Santa Clara field (including the fault map) generated after interpreting its 3D seismic.

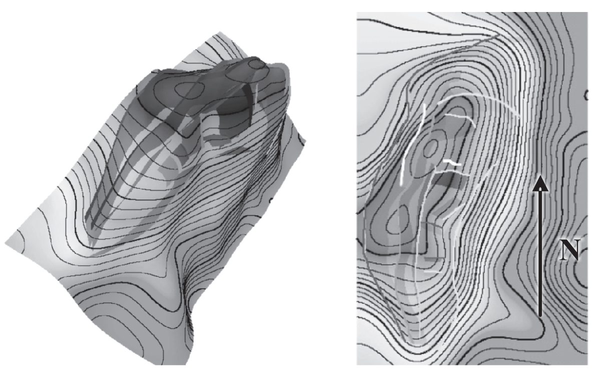

Figure 2. Structural model for Santa Clara field

The western flank of the anticlinal limits with the Santa Clara fault. The eastern flank has its own closing. The structure of the field shows that the slope on the western flank is 6° less than the one to the East where it reaches 9°. From the Santa Clara fault several inverse sealing nature faults are derived (satellites) with a main orientation of SW-NE-E, generating several blocks within the field, thus controlling their fluid flow. There are 14 faults identified within the field.

Stratigraphic description

The producer formation in the Santa Clara field is known as the Caballos formation, and it has been commonly divided into three sub-formations. Upper, mid and lower Caballos. Upper Caballos (UKB), is the main producing reservoir at the Santa Clara field. It has a thickness between 120 and 150 feet. The Upper Caballos formation is subdivided stratigraphically into three units from top to base: UKB1, UKB2 (30-50 foot thickness), UKB3 (30-50 foot thickness). The Middle Caballos formation (MKB) has an average thickness of 120 feet and it is subdivided into three units, MKB, MKB1, MKB2. The Lower Caballos formation (LKB) rests conflictingly on the basement and is comprised of three stratigraphic units, LKB, LKB2, LKB3 with a total average thickness of 150 feet. Both the isopach maps, as well as those for net sand show a NW-SE orientation of the sandy bodies.

Table 1 shows a representation of the stratigraphic units within the static model. Units UKB and LKB represent the units with the greatest contribution to production at Santa Clara, while the MKB unit is a formation with more argillecaeous bodies, and is less productive.

Upper Caballos exhibits the best petrophysical properties in the reservoir with porosity between 16 and 20% and permeability between 100 and 300 md, initial water saturation at the reservoir was 22%. The field has a productive area of 752 acres and there is 40 to 60 acre spacing between wells.

Table 1. Sand distribution on the grid

FORMATION	SAND	STRATUS WITHIN THE MODEL
Upper Caballos	UKB1	1
	UKB2	2 to 11
	UKB3	12 to 21
Mid Caballos	MKB1	22 to 26
	MKB2	27 to 31
	MKB3	32
Lower Caballos	LKB1	33 to 42
	LKB2	43 to 52
	LKB3	53 to 62

DYNAMIC MODEL

Once the static model was generated, it was exported to the simulator in order to develop the dynamic model which was integrated with rock fluid properties (relative permeability and capillary pressures), modeling and PVT property match , initialization conditions and well history.

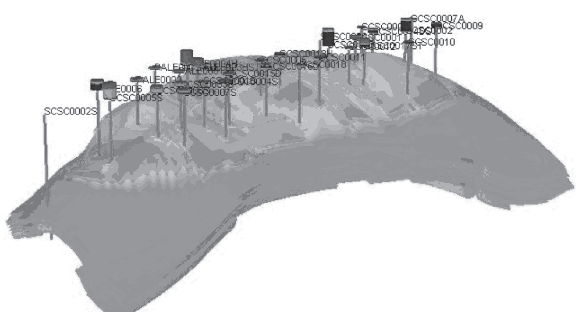

Figure 3. Dynamic model for Santa Clara field

Modelling of fluids

Crude oil at the Santa Clara field is a viscous oil (26-65cp), reservoir temperature 116°F (319,81 K), with an API gravity of nearly 18°. Bubble point pressure is close to 1100 psi. For modeling and adjustments, the last PVT data obtained for the field was employed (Barrios, 2004), based on this information, the modeling of the fluid properties was done in the fluid simulator. This allowed us to create a composition fluid and properties similar to the real scenario, adjusting it by means of a parametric regression and exporting its thermodynamic properties as equilibrium constants.

The composition of the original fluid characterized in the PVT Laboratory at the ICP was initially reduced to 11 components, without including water. Due to the numerical difficulties presented by the hardware to be able to perform the simulation processes, a new componet set was generated for three components (live oil system with three components: water, oil and gas). This end fluid model allowed us to balance the number of calculations and simulation time.

Relative permeabilities

A set of relative permeabilities were used from laboratory tests done on several samples (Amaya, 2004). For the reservoir having neutral wettability with a tendency to be oil wet, the residual oil saturation is 40%; but upon heating, it was observed that the value could decrease to 20%.

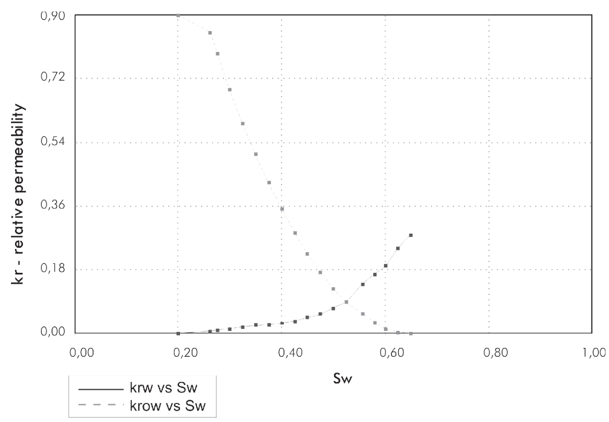

Figure 4. Relative permeability

Initialization conditions

Initial pressure and depth conditions were estimated at 1217 psi and 600 ft - TVDSS. Original water oil contracts and gas oil contacts were estimated at 850 feet and 250 feet respectively; although these figures are presented with some degree of uncertainty, for this reason they were reviewed during the historical adjustment phase, bearing in mind that they directly affect the behavior of production and pressure in the field.

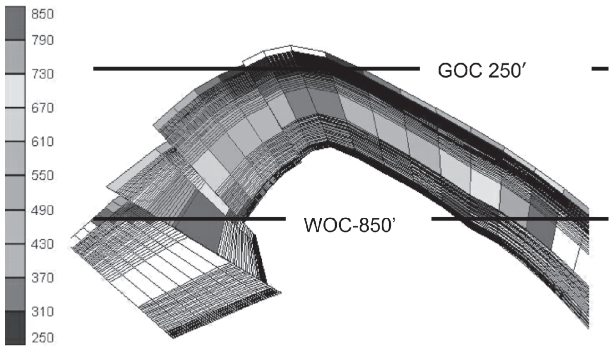

Figure 5. Contact location

Initial fluids in the reservoir were the following:

Pore volume:	3,33313E+08 rbbl
Total gas in situ:	2,80259E+10 SCF
Free gas in situ:	2,22308E+09 SCF
Solution gas in situ:	2,58028E+10 SCF
Total oil in situ:	1,29316E+08 STB
Total water in situ:	1,84161E+08 STB

The Santa Clara field has been exploited since 1987 at its Caballos formation in three units: Upper Caballos, Middle Caballos and Lower Caballos; Upper Caballos being responsible for more than 90% of production. Production mechanisms are a layer of gas, gas solution and active partially aquifer drive. As of the year 2005 oil production topped 10,5 MMBBL, in other words an approximate recovery factor of 8,6%.

HISTORY MATCH

Once reservoir pore volume, static and dynamic reservoir models were integrated and validated, pressure and fluid production were adjusted in the field. It was decided that liquid rate would be used for history matching, since we were dealing with a field with large water production and active aquifer. By using this control, the aquifer restored pressure caused by well production. The match covered aquifer modeling, location of water oil contacts for each production unit, illumination of the isolated areas near the wells and handling of preferential waterflow channels within the reservoir.

Size and type of aquifer

After a profound analysis of the structure of the field, it was determined that the only way to guarantee pressure support for the upper area (UKB) of the reservoir was by means of a lateral aquifer connection. This was due to the existence of a shale seal that would not allow pressure support caused by the bottom aquifer (method in usually used) to affect the Upper Caballos unit. The aquifer was respresented by the Carter-Tracy model (infinite extension).

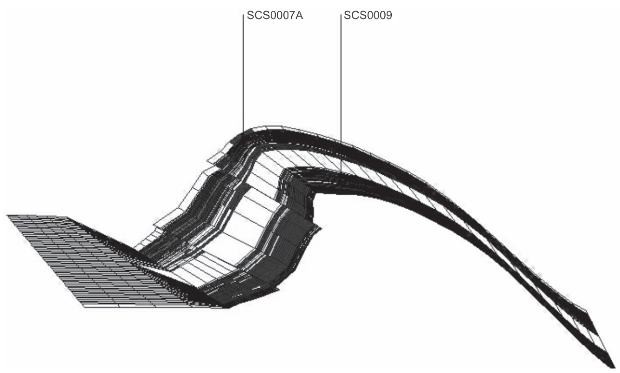

Figure 6. Regional division between Upper Caballos and Lower Caballos

Location of contacts

Due to the initial water production behavior study at certain wells (for example: SC9) differences were observed between the real results and those of the simulator. In the case of SC9, the well was drilled initially to a depth of 1014 feet, bearing in mind the depth of the contact at 850 feet, it would be concluded that there are more than 150 feet of intervals drilled in water areas that would cause that the original water production be higher than the actual. For this reason, two different WOC contacts where placed for the units at Upper Caballos and Lower Caballos, dividing the reservoir into two initialization areas: Region one (Upper Caballos) with a contact at 870 feet and Region two (Caballos inferior) with a contact at 1025 feet.

To summarize, 19 years of production, at 28 wells were matched from the Santa Clara and Palermo fields. The results are shown in the following figures:

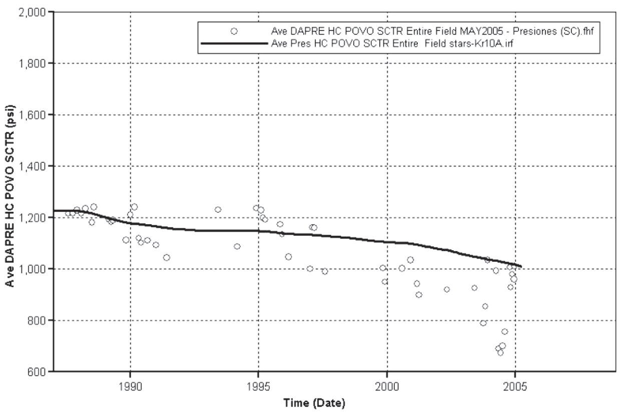

Figure 7. Reservoir pressure match

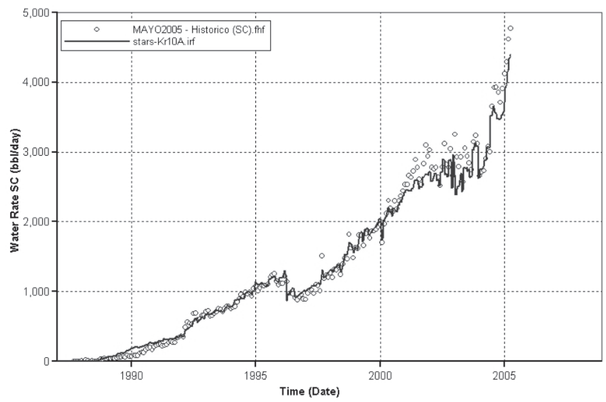

Figure 8. Field water production match

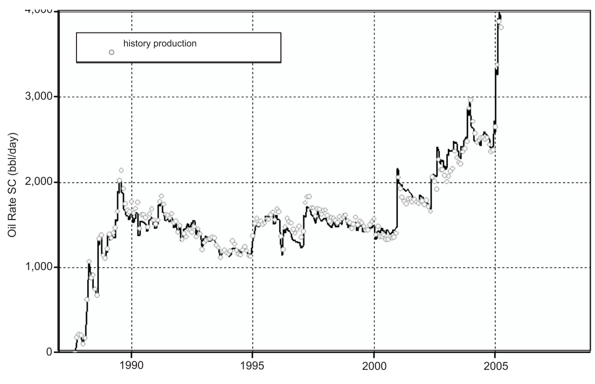

Figure 9. Field oil production match

CYCLIC STEAM INJECTION

Laboratory tests

Once the best technology was defined for developing the Santa Clara field, steam injection started (Barrios, *et al.*, 2003), several lab tests were designed and applied. These tests were carried out seeking to complete reservoir data necessary to numerically model these types of processes. Among the tests performed the following were assessed: ock compressibility, relative permeability curve behavior at different temperatures, formation sensitivity to injection fluids, DRX analysis and residual saturation of crude oil for steam injection.

Rock compresibility. CMS-300 equipment was used to calculate pore volume compresibility for the rock and runs were generated at various pressures, bearing in mind the confinement pressure and initial and end reservoir pressures. The results obtained were the following:

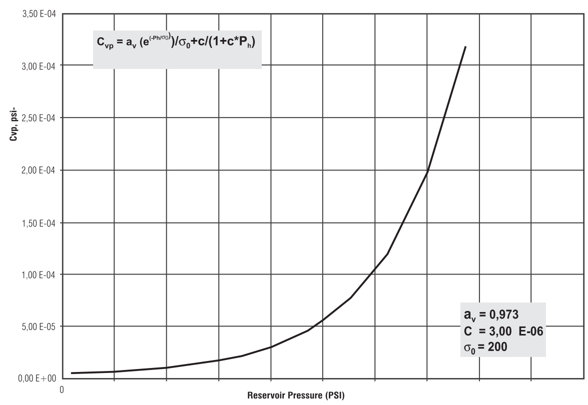

Figure 10. Rock compresibility

Relative permeability. Relative permeability curves were determined for three samples, at two different temperatures. Reservoir temperature 118ºF (320,92 K) and steam injection temperature 280ºF (420,92 K). The purpose of this study was to evaluate the influence of temperature on relative permeability of the fluids. The displacements were done on long composite samples, made up of two cores. The samples were grouped according to their air permeability. The resulting samples were placed in three different permeability ranges: low (~3 mD), medium (~86 mD) and high (~250 mD); corresponding to the three different types of rock at the reservoir.

The measurement method used was the water flooding technique, at a non-stable condition in restored samples. These samples were subjected to a wettability restoration process, after cleaning with solvents at 80°C (353,15 K).

The results obtained show that there is a significant influence on crude oil residual saturation. Residual saturation changes from ~40% at 118ºF (320,92 K) to ~20% at 280ºF (410,92 K). The effect on the shape of the curves is also noticeable. Crude oil effective of permeability increases and effective permeability to water reduces with increasing temperature.

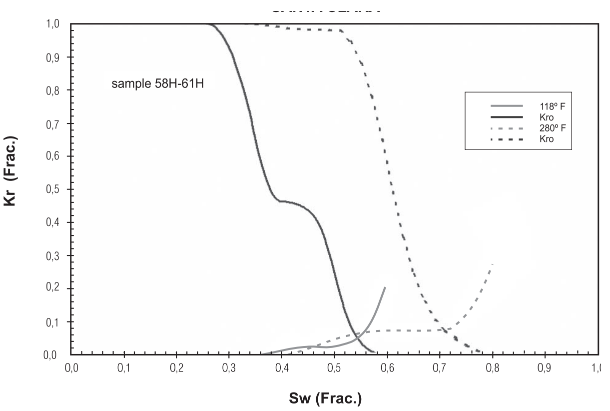

Figure 11. Temperature influence on relative permeability

Formation sensitivity. It is well known that the interactions between rock and different injected fluids may lead to a decrease in formation permeability for the regions and exposed to thermal injection. However, in steam injection processes an increase in permeability is produced because a dilation in the rock matrix is generated due to production of thermal changes.

Throughout the study, cores were used from samples derived from Palermo-2 well, which were supplied by Hocol de Colombia Limited. Crude oil from Santa Clara 15 well, gas from Santa Clara -13, and production water from the Santa Clara-10 well and distilled water type I from Santa Clara 3 were used in tests.

It was seen that in all cores hot water was able to move at injection rates as high as 32,0 cm^3/min, which is equivalent to a rate of 3,153 STB/D in the field, for a net petroleum pay of 60 feet. These high water flows assured steam injectivity at Santa Clara field.

Formation permeability remains constant during the two steam displacements, showing lesser changes in the amounts recorded, before and after the injection. As the figure shows:

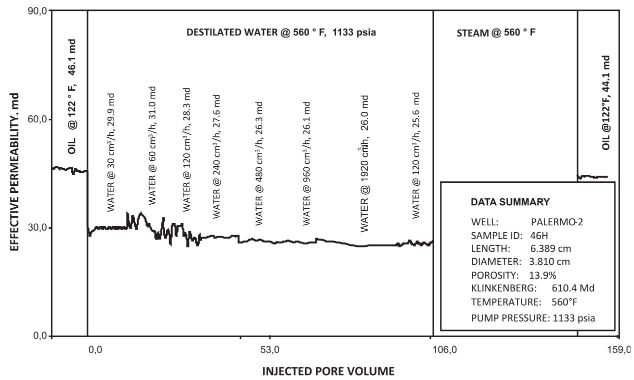

Figure 12. Sensitivity at Palermo-2, 46H, 560°F (566,48 K)

On another front, based on the type 1 analysis on crude oil from five wells at Santa Clara field, it was possible to observe that there were no precipitation problems for paraffins since their fluid point is –24°C –11,2°F (249,15 K), which is a lower minimum temperature than that required for working conditions: More or less 26°C (299,15 K) or 80°F (299,81 K).

In the physical and chemical analysis it may be seen that there is a high content of bicarbonate ions at an average of 1450 ppm at all wells, which may precipitate as calcium carbonate by decreasing reservoir pressure. This would lead to the reduction of permeability for plugging.

The CO_2 content in production water at the Santa Clara field, greater than 100 ppm at every well, may contribute to develope corrosion phenomena.

DRX Analysis. These tests were run showing that sands from Upper Caballos exhibit high concentration of quartz and low presence of clay minerals, some traces of pyrite and possible ferrous oxides.

The clay is basically kaolinite; ilite mica reaches nearly 10%, and there is a very low concentration of smectites, no higher than 1% of the lowest fraction of two micras. Microcrystaline Quartz is found in large portions in the deepest sample, where the presence of clays is minimal.

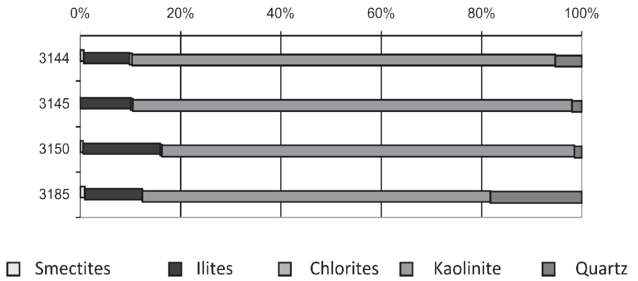

Figure 13. Clay distribution in the reservoir

Residual oil saturation. The table shows residual oil saturation after flooding the formation at 300ºF, 400ºF and 560°F (422,03 K, 477,59 K and 566,48 K), respectively.

Tabla 2. Residual saturation of oil to steam (after an steamflooding at Palermo-2)

Tipo Roc	I.D.	Depth. (feet)	Por. (%)	Klink, (md)	Reservoi (r)	Temp., (°F)	Sor. st, % Lab.	Sor. st, % Dean Stark
1	27H	3159	13,8	433,3	UKB	300	13,0	20,0
	47H	3186	14,1	443,6	UKB			
	22H	3154	12,5	257,1	UKB			
	10H	3142	15,2	429,2	UKB			
1	44H	3183	13,7	291,4		400	6,0	
	45H	3184	13,6	257,7				
	43H	3182	15,1	244,1				
	16H	3148	15,0	194,0				
1	9H	3141	13,7	116,5		560	9,0	
	29H	3161	17,2	211,4				
	14H	3146	13,7	86,5				
	15H	3147	13,9	86,6				

During displacements it was observed that residual crude oil saturation may be diminished from 40% to values around 13% and 6%, meanwhile a steam injection process is used.

Numerical Simulation

A cyclic injection process was simulated for the Santa Clara and Palermo fields, looking for the evaluation of the reservoir response to this recovery process. 30 wells were stimulated using sequential operations, starting in the South sector of the field.

Initial conditions for the injection process were schematized based on thermal projects, performed on similar fields, and supported by "analogy application for improved recovery processes" software (Soto, 2005).

- Injection pressure: 1250 psi
- Injection temperature: 572ºF (573,15)
- Steam quality: 0,8
- Injection time: 15 days
- Soaking period: 3 days
- Injection rate: 1200 Bbls/day
- Mechanical conditions of the well: thermal cementing, thermal tubing

The last item assumes that all wells are mechanically adapted for steam injection. In other words, they have been completed with thermal cement and special tubing, this is true for the latest wells that have been drilled in the field. It is important to note that the first few wells would have to be reconditioned to support this process.

Once favorable results were observed for the first cyclic injection, sensitivity parameters were established in order to optimize the process and to obtain the best response from the reservoir.

Process sensitivity and optimization

Injection time-rate and injected heat. The injection rate was the first parameter evaluated. the thickness to be flooded area is considerable, especially for sloped and horizontal wells.

When defining to the injection rate, there are other parameters taken into account such as:

- Generator capacity
- Injection time

According to the literature (Farouq, 1983) and lessons learned from other similar projects, the minimum quantity of heat injected per foot has been established to vary between 50 - 80 MMBTU. Seeking to obtain the minimum production deferred and maximizing (maximize) generator work, all simulation calculations were based on using a 50 MM BTU/HR steam generator. This implies that steam injection conditions (pressure and temperature) were handled at a fixed daily injection rate of 3250 Bbls for every well in the field. The injection time for each well was also varied according to the formation thickness to be contacted.

Bearing in mind the thickness for each of the wells, two sensitivities were proposed for injection: 50 MMBTU/FT and 80 MMBTU / FT, obtaining variable injection times, then running three more with set injection times for all wells of 15,21 and 30 days.

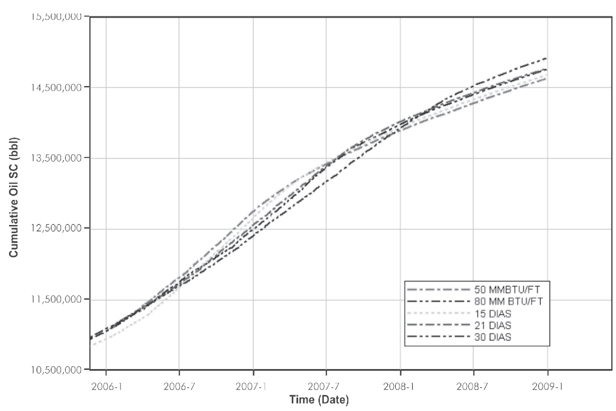

Figure 14. Injection time sensitivity/injected heat-daily and accumulated production

Production peaks fluctuate strongly with the heat injected and the injection time (Figure 14), each well has its own optimum injection period, and thus the importance of the sensitivities. Having performed sensitivities and analyzed daily production as well as accumulated field production, an injection time was defined for each well:

Table 3. Time and optimal injection per well

No.	Well	50MM BTU/FT	50MM BTU/FT	15 D	21 D	30 D
1	SC-8S			x		
2	SC-9S			x		
3	PAL6			x		
4	SC6s			x		
5	SC7s			x		
6	SC3s			x		
7	PAL2					x
8	SC1s					x
9	SC5s				x	
10	Sc4s					
11	SC15D			x		
12	PAL1ST		x			
13	PAL5HST		x			
14	PAL4H		x			
15	PAL3HST		x			
16	SC16D					
17	SC5			x		
18	SC18			x		
19	SC13H			x		
20	SC11					
21	SC3					
22	SC12					
23	SC17ST			x		
34	SC1			x		
25	SC10					
26	SC14DST			x		
27	SC6					
28	SC2					
29	SC9			x		
30	SC7a					

Injection pressure and temperature. At the beginning of the sensitivity studies it was necessary to evaluate under which probable scenario it would be possible to obtain better recovery, bearing in mind that the current reservoir pressure (800-1000 psi) was high. For this reason it was impossible to inject under these pressures. Likewise, injection pressures obtained during lab tests were used as a reference proving that it was possible to inject at high pressure, without causing serious damage to the formation in question.

- Steam was injected at 4 pressure values (900-1250-1500-1700 psi)

The following are the results:

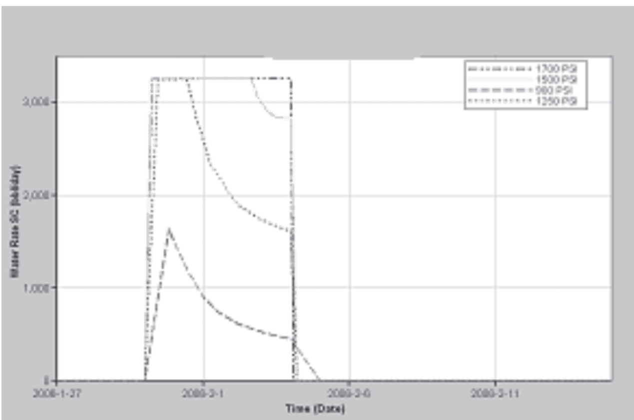

Figure 15. Injectivity for PAL-2 well

Injectivity was initially evaluated for each of the wells, observing that the higher the injection pressureas was expected, the lower the quantity of water and steam needed to flood the reservoir. It is concluded that the greater the injection pressure, the better injectivity for the Santa Clara and Palermo wells. It was observed that almost every well showed a favorable response above 1250 psi, but in general the majority presented injectivity problems, especially due to the high pressure of these wells and a high rate of injection being handled.

The following table summarizes the wells with injectivity problems:

Table 4. Wells with injectivity problems

WELLS (14)
SC-8S
SC-9S
SC-7S
SC-3S
PAL-2
SC-1S
SC-4S
SC-18
SC-9
SC-7A
SC-11
SC-12
SC10
SC-6

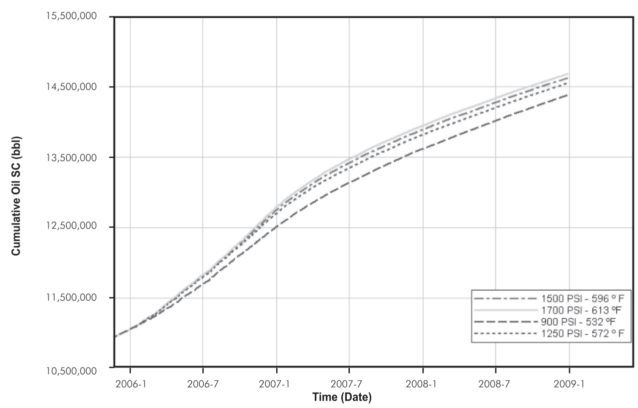

Figure 16. Injectivity – accumulated production

Likewise, it is possible to observe a favorable behavior in production when steam is injected at high pressures. However, in some wells the behavior was the same when injecting at 1250 psi or at 1700 psi.

Soaking period. 1, 2, 3 and 5 day soaking sensitivities were performed, in order to observe its direct behavior on production. It was observed that the influence of this parameter on well behavior was the minimum. More than anything, this time span will depend mostly on the mechanical condition of the well and the time the operator takes to remove the injection string and place it in production. Nevertheless, some wells showed favorable behavior with longer times.

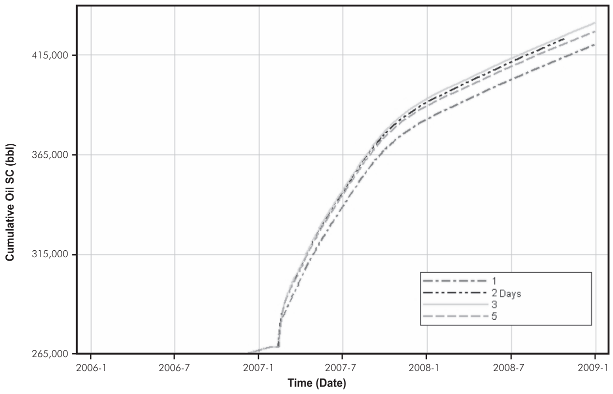

Figure 17. Sensitivity to soaking period-accumulated production

Steam quality. Sensitivities were performed at 0,6; 0,7; 0,8 and 0,9. A slight increase was observed in the daily production rate with increasing quality. For cumulative production, both for the field as well as for the wells, the increase was not considerable. Favorable behavior was observed in some wells showing better injectivity with lower quality.

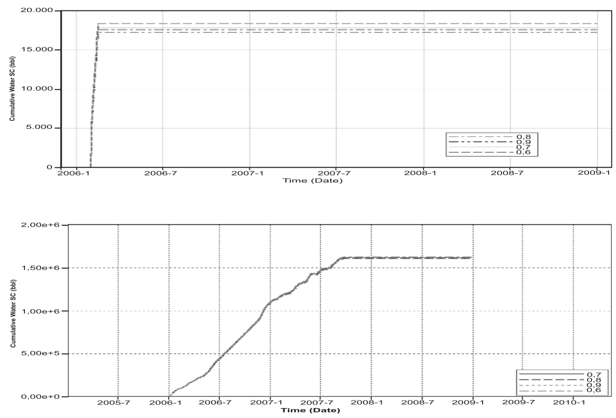

Figure 18. Steam quality sensitivity-injected water and accumulated production

INJECTION CYCLES

Once the injection process was optimized, the following operating conditions were established:

Table 5. Optimum injection conditions

Injection wells	30
Start of injection	01-12-2005
Steam quality (%)	80
Injection pressure (psi)	1500
Injection temperature (°F)	596
Injection rate (BBLS/D)	3250
Soaking period (days)	2-3
Average injection time per well (days)	22,5
Cycle duration (injection- production) (days)	315
Injected water per cycle * well	73195
Number of cycles:	3-6

First injection cycle. The injection schedule was the following: this graph shows the sequential order for each well flooded with steam, the time lapse of the injection (starting and ending dates), date when it was put into production, duration of the cycle, in other words the period when it was first injected, it began to produce and reach the initial rate that it had before injection (cold production).

Table 6. Schedule injection for first cycle

FIRST CYCLE SCHEDULE							
N°	Well	Start Injection	End Injection	Start production	Injected days	End cycle	Cycle duration
1	SC-8S	1-dic-05	15-dic-05	17-dic-05	14	1-jan-07	396
2	SC-9S	16-dic-05	31-dic-05	2-jan-06	15	20-jul-06	216
3	PAL6	31-dic-05	15-jan-06	17-jan-06	15	26-sep-06	269
4	SC6s	16-jan-06	31-jan-06	2-feb-06	15	16-sep-06	243
5	SC7s	1-feb-06	16-feb-06	18-feb-06	15	31-oct-06	272
6	SC3s	17-feb-06	4-mar-06	6-mar-06	15	26-apr-07	433
7	PAL2	5-mar-06	4-apr-06	6-apr-06	30	12-mar-07	738
8	SC1s	5-apr-06	5-may-06	7-may-06	30	5-mar-07	334
9	SC5s	6-may-06	25-may-06	26-may-06	19	2-jan-07	241
10	SC4s	26-may-06	10-jun-06	12-jun-06	15	7-mar-07	285
11	SC15D	11-jun-06	25-jun-06	26-jun-06	14	18-feb-07	252
12	PAL1ST	26-jun-06	3-jul-06	5-jul-06	7	30-may-07	338
13	PAL5HST	4-jul-06	7-aug-06	9-aug-06	34	16-nov-07	500
14	PAL4H	8-aug-06	14-oct-06	16-oct-06	67	25-jan-08	535
15	PAL3HST	15-oct-06	17-dic-06	19-dic-06	63	23-nov-07	404
16	SC16D	24-nov-06	24-dic-06	26-dic-06	30	29-sep-07	309
17	SC5	25-dic-06	9-jan-07	11-jan-07	15	22-dic-07	362
18	SC18	10-jan-07	25-jan-07	27-jan-07	15	14-jul-07	185
19	SC13H	26-jan-07	10-feb-07	13-feb-07	15	7-oct-07	254
20	SC11	11-feb-07	13-mar-07	15-mar-07	30	25-oct-07	256
21	SC3	14-mar-07	13-apr-07	15-abr-07	30	21-oct-07	221
22	SC12	14-apr-07	28-may-07	29-may-07	44	9-sep-07	148
23	SC17ST	13-may-07	26-may-07	27-may-07	13	26-nov-07	197
24	SC1	27-may-07	11-jun-07	13-jun-07	15	12-mar-08	290
25	SC10	12-jun-07	17-jun-07	19-jun-07	5	7-jan-08	209
26	SC14DST	18-jun-07	3-jul-07	5-jul-07	15	8-dic-07	173
27	SC6	4-jul-07	3-aug-07	5-aug-07	30	31-dic-08	546
28	SC2	4-aug-07	3-sep-07	5-sep-07	30	10-may-08	280
29	SC9	4-sep-07	19-sep-07	21-sep-07	15	26-oct-08	418
30	SC7a	20-sep-07	25-sep-07	27-sep-07	5	25-jan-08	127

The above table shows the results obtained, showing oil produced during this period of time if there were steam injection and showing which will be the incremental production of the process. produced/steam injected ratio (equivalent barrels of water) was calculated for every well, since this is the main economic indicator for the project.

Duration of the first cycle had an average of 314 days, fluctuating between 127-738 days. Steam was injected during 675 days, it was observed an increasing production of 583,000 Bbls, in other words an increase of 72% of production that would have had primary recovery in the field.

Table 7. Results: first cycle

RESULTS: FIRST INJECTION CYCLE						
Nº	Well	Injection-poduction Time (Days)	Oil Primary production (Bbls)	oil incremental production (Bbls)	% Increase	Increase oil daily (Bbls/Day)
1	PAL4H	535	105936	101481	95,8	190
2	PAL3HST	404	73041	80644	110,4	200
3	SC3	221	54380	62602	115,1	283
4	SC2	280	47120	45872	97,4	164
5	PAL2	738	79952	41831	52,3	57
6	SC16D	309	35845	38974	108,7	126
7	SC6s	243	54205	29157	53,8	120
8	PAL5HST	500	33716	18693	55,4	37
9	SC5	362	16960	17227	101,6	48
10	PAL1ST	338	26834	15192	56,6	45
11	SC15D	252	21232	15180	71,5	60
12	SC5s	241	55262	14959	27,1	62
13	SC4s	285	21993	12946	58,9	45
14	PAL6	269	15781	11894	75,4	44
15	SC3s	433	36142	10789	29,9	25
16	SC13H	254	14237	8868	62,3	35
17	SC1s	334	8662	7353	84,9	22
18	SC-8S	396	25940	7168	27,6	18
19	SC14DST	173	11901	7146	60,0	41
20	SC6	546	11195	6708	59,9	12
21	SC-9S	216	14108	6008	42,6	28
22	SC1	290	10352	5777	55,8	20
23	SC11	256	6392	4731	74,0	18
24	SC9	418	9894	4006	40,5	10
25	SC17ST	197	7300	3848	52,7	20
26	SC7s	272	9354	2912	31,1	11
27	SC12	148	1695	701	41,3	5
28	SC7a	127	1477	428	29,0	3
29	SC10	209	986	195	19,8	1
30	SC18	185	441	193	43,8	1
	TOTAL	**9431**	**812,333**	**583,485**	**71,8**	**1751**
Average (30 WELLS)		**314,366667**				**63**

OIL STEAM RATE: First Cycle					
N°	Well	Injected days	Injected Water	Oil incremental production	OSR
1	PAL1ST	7	22750	15192	0,67
2	SC3	30	97500	62602	0,64
3	SC6s	15	48750	29157	0,60
4	SC2	30	97500	45872	0,47
5	PAL4H	67	217750	101481	0,47
6	PAL2	30	97500	41831	0,43
7	SC16D	30	97500	38974	0,40
8	PAL3HST	63	204750	80644	0,39
9	SC5	15	48750	17227	0,35
10	SC15D	14	45500	15180	0,33
11	SC4s	15	48750	12946	0,27
12	PAL6	15	48750	11894	0,24
13	SC5s	19	61750	14959	0,24
14	SC3s	15	48750	10789	0,22
15	SC13H	15	48750	8868	0,18
16	PAL5HST	34	110500	18693	0,17
17	SC-8S	14	45500	7168	0,16
18	SC14DST	15	48750	7146	0,15
19	SC-9S	15	48750	6008	0,12
20	SC1	15	48750	5777	0,12
21	SC17ST	13	42250	3848	0,09
22	SC9	15	48750	4006	0,08
23	SC1s	30	97500	7353	0,08
24	SC6	30	97500	6708	0,07
25	SC7s	15	48750	2912	0,06
26	SC11	30	97500	4731	0,05
27	SC7a	5	16250	428	0,03
28	SC10	5	16250	195	0,01
29	SC12	44	143000	701	0,005
30	SC18	15	48750	193	0,004
	TOTAL		**2,193,750**	**583,485**	**0,27**

The average OSR for the wells was 0,27 and was higher than 0,5 in some wells. The percentage injectivity for this first cycle was 71% and injected energy on the average was 126 million BTU/FT.

Second injection cycle. The injection schedule is in Table 8:

Table 8. Scheduled injection for second cycle

FIRST CYCLE SCHEDULE							
N°	Well	Start Injection	End Injection	Start production	Injected days	End cycle	Cycle duration
1	SC-9S	20-jul-06	4-aug-06	6-aug-06	15	11-jan-07	175
2	SC6s	16-sep-06	1-oct-06	3-oct-06	15	17-may-07	243
3	PAL6	26-sep-06	11-oct-06	13-oct-06	15	22-jun-07	269
4	SC7s	31-oct-06	15-nov-06	17-nov-06	15	12-jun-07	224
5	SC-8S	1-jan-07	15-jan-07	17-jan-07	14	1-jan-08	365
6	SC5s	2-jan-07	21-jan-07	22-jan-07	19	14-jul-07	193
7	SC15D	18-feb-07	4-mar-07	5-mar-07	14	29-jun-08	497
8	SC1s	5-mar-07	4-apr-07	6-apr-07	30	3-feb-08	335
9	SC4s	7-mar-07	22-mar-07	24-mar-07	15	26-jul-08	507
10	SC3s	26-apr-07	11-may-07	13-may-07	15	3-jul-08	434
11	PAL1ST	30-may-07	6-jun-07	8-jun-07	7	11-dic-07	195
12	SC18	14-jul-07	29-jul-07	31-jul-07	15	25-jan-08	195
13	SC12	9-sep-07	23-oct-07	24-oct-07	44	2-apr-08	206
14	SC16D	29-sep-07	29-oct-07	31-oct-07	30	3-oct-08	370
15	SC13H	7-oct-07	22-oct-07	25-oct-07	15	10-jul-08	277
16	SC3	21-oct-07	20-nov-07	22-nov-07	30	16-jul-08	269
17	SC11	25-oct-07	24-nov-07	26-nov-07	30	10-sep-08	321
18	PAL5HST	16-nov-07	20-dic-07	22-dic-07	34	31-dic-08	411
19	PAL3HST	23-nov-07	25-jan-08	27-jan-08	63	28-oct-08	340
20	SC17ST	26-nov-07	9-dic-07	10-dic-07	13	3-aug-08	251
21	SC14DST	8-dic-07	23-dic-07	25-dic-07	15	3-jun-08	178
22	SC5	22-dic-07	6-jan-08	8-jan-08	15	10-sep-08	263
23	SC10	7-jan-08	12-jan-08	14-jan-08	5	27-sep-08	264
24	PAL4H	25-jan-08	1-apr-08	3-apr-08	67	28-jan-09	369
25	SC7a	25-jan-08	30-jan-08	1-feb-08	5	30-nov-08	310
26	PAL2	12-mar-08	11-apr-08	13-apr-08	30	25-apr-09	409
27	SC1	12-mar-08	27-mar-08	29-mar-08	15	6-feb-09	331
28	SC2	10-may-08	9-jun-08	11-jun-08	30	28-dic-08	232
29	SC9	26-oct-08	10-nov-08	12-nov-08	15	30-jun-09	247
30	SC6	31-dic-08	30-jan-09	1-feb-09	30	31-dic-09	365

The top half of Table 8 shows the results for the second cycle. The bottom half of Table 9 shows the accumulated results (first and second cycles) obtained:

Table 9. Results: second cycle

RESULTS: FIRST AND SECOND INJECTION CYCLE						
N°	WELL	Injection-poduction Time (Days)	Oil Primary production (Bbls)	oil incremental production (Bbls)	% Increase	Increase oil daily (Bbls/Day)
1	PAL4H	904	160313	169005	105,4	187
2	PAL3HST	744	141194	154108	109,1	207
3	SC3	490	131380	118077	89,9	241
4	SC16D	679	75791	83407	110,0	123
5	PAL2	1147	117757	83076	70,5	72
6	SC6s	486	103644	50972	49,2	105
7	PAL5HST	911	60762	40552	66,7	45
8	SC5s	434	86890	39996	46,0	92
9	SC4s	792	49993	38500	77,0	49
10	SC15D	749	58164	38270	65,8	51
11	SC2	512	63125	29333	46,5	57
12	SC5	625	27960	28370	101,5	45
13	PAL1ST	533	40834	27377	67,0	51
14	PAL6	538	26781	23897	89,2	44
15	SC3s	867	61697	18441	29,9	21
16	SC6	911	17728	18101	102,1	20
17	SC1	621	23352	18015	77,1	29
18	SC13H	531	30237	15931	52,7	30
19	SC11	577	12762	15459	121,1	27
20	SC1s	669	15952	13758	86,2	21
21	SC-8S	761	37670	13379	35,5	18
22	SC-9S	391	25148	12673	50,4	32
23	SC17ST	448	20000	10477	52,4	23
24	SC14DST	351	22710	9916	43,7	28
25	SC9	665	15394	7765	50,4	12
26	SC7s	496	14654	5955	40,6	12
27	SC7a	437	5777	2487	43,1	6
28	SC12	354	3630	876	24,1	2
29	SC18	380	1029	783	76,1	2
30	SC10	473	2486	774	31,2	2
	TOTAL	**18476**	**1,454,814**	**1,089,730**	**74,9**	**1655**
Average (30 WELLS)		**615,866667**				**59**

OIL STEAM RATE: First and Second Cycle					
Nº	Well	Injected days	Injected Water	Oil incremental production	OSR
1	SC3	60	195000	118077	0,61
2	PAL1ST	14	45500	27377	0,60
3	SC6s	30	97500	50972	0,52
4	SC16D	60	195000	83407	0,43
5	PAL2	60	195000	83076	0,43
6	SC15D	28	91000	38270	0,42
7	SC4s	30	97500	38500	0,39
8	PAL4H	134	435500	169005	0,39
9	PAL3HST	126	409500	154108	0,38
10	SC5s	38	123500	39996	0,32
11	SC5	30	97500	28370	0,29
12	PAL6	30	97500	23897	0,25
13	SC3s	30	97500	18441	0,19
14	SC1	30	97500	18015	0,18
15	PAL5HST	68	221000	40552	0,18
16	SC13H	30	97500	15931	0,16
17	SC2	60	195000	29333	0,15
18	SC-8S	28	91000	13379	0,15
19	SC-9S	30	97500	12673	0,13
20	SC14DST	26	84500	10477	0,12
21	SC17ST	30	97500	9916	0,10
22	SC6	60	195000	18101	0,093
23	SC9	30	97500	7765	0,080
24	SC11	60	195000	15459	0,08
25	SC7a	10	32500	2487	0,08
26	SC1s	60	195000	13758	0,07
27	SC7s	30	97500	5955	0,06
28	SC10	10	32500	774	0,02
29	SC18	30	97500	783	0,01
30	SC12	88	286000	876	0,00
	TOTAL		**4,387,500**	**1,089,730**	**0,25**

The duration of the second cycle had an average 302 days, fluctuating between 507-175 days, performing steam injection during 675 days. An increase in production(cycles 1 and 2) of 506,230 Bbls was observed and acumulative production reached 1,089,730 Bbls, in other words an increase of 75% of production that the field would have had in primary recovery. The average OSR for wells was 0,25, reaching higher than 0,5 in some wells. Percentage injectivity for this first cycle was 90% and injected energy on the average was 165 million BTU/FT.

Third injection cycle. The injection schedule is shown in Table 10.

Table 10. Scheduled injection for third cycle

THIRD CYCLE SCHEDULE							
N°	Well	Start Injection	End Injection	Start production	Injected days	End cycle	Cycle duration
1	SC-9S	11-jan-07	26-jan-07	28-jan-07	15	7-jul-07	177
2	SC6s	17-may-07	1-jun-07	3-jun-07	15	4-nov-07	171
3	SC7s	12-jun-07	27-jun-07	29-jun-07	15	25-jan-08	227
4	PAL6	22-jun-07	7-jul-07	9-jul-07	15	23-feb-08	246
5	SC5s	14-jul-07	2-aug-07	3-aug-07	19	6-jan-08	176
6	PAL1ST	11-dic-07	18-dic-07	20-dic-07	7	27-sep-08	291
7	SC-8S	1-jan-08	15-jan-08	17-jan-08	14	26-jul-08	207
8	SC18	25-jan-08	9-feb-08	11-feb-08	15	20-oct-08	269
9	SC1s	3-feb-08	4-mar-08	6-mar-08	30	27-jul-09	540
10	SC12	2-apr-08	16-may-08	17-may-08	44	25-dic-08	267
11	SC14DST	3-jun-08	18-jun-08	20-jun-08	15	3-feb-09	245
12	SC15D	29-jun-08	13-jul-08	3-aug-08	14	22-jun-09	358
13	SC3s	3-jul-08	18-jul-08	20-jul-08	15	18-apr-09	289
14	SC13H	10-jul-08	25-jul-08	28-jul-08	15	25-aug-09	411
15	SC3	16-jul-08	15-aug-08	17-aug-08	30	2-mar-09	229
16	SC4s	26-jul-08	10-aug-08	12-aug-08	15	5-apr-09	253
17	SC17ST	3-aug-08	16-aug-08	17-aug-08	13	9-feb-09	190
18	SC11	10-sep-08	10-oct-08	12-oct-08	30	8-jan-10	485
19	SC5	10-sep-08	25-sep-08	27-sep-08	15	29-jul-09	322
20	SC10	27-sep-08	2-oct-08	4-oct-08	5	9-jun-09	255
21	SC16D	3-oct-08	2-nov-08	4-nov-08	30	3-dic-09	426
22	PAL3HST	28-oct-08	30-dic-08	1-jan-09	63	7-aug-09	283
23	SC7a	30-nov-08	5-dic-08	7-dic-08	5	29-jun-09	211
24	SC2	28-dic-08	27-jan-09	29-jan-09	30	11-sep-09	257
25	PAL5HST	31-dic-08	3-feb-09	5-feb-09	34	25-aug-09	237
26	PAL4H	28-jan-09	5-apr-09	7-apr-09	67	30-jan-10	367
27	SC1	6-feb-09	21-feb-09	23-feb-09	15	3-dic-09	300
28	PAL2	25-apr-09	25-may-09	27-may-09	30	15-jan-10	265
29	SC9	30-jun-09	15-jul-09	17-jul-09	15	8-feb-10	223
30	SC6	31-dic-09	30-jan-10	1-feb-10	30	17-dic-10	351

Table 11. Third cycle results

RESULTS: FIRST INJECTION CYCLE						
Nº	WELL	Injection-poduction Time (Days)	Oil Primary production (Bbls)	oil incremental production (Bbls)	% Increase	Increase oil daily (Bbls/Day)
1	PAL4H	1271	197749	235307	119,0	185
2	PAL3HST	1027	191694	221932	115,8	216
3	SC3	719	192380	171835	89,3	239
4	SC2	769	128120	142560	111,3	185
5	SC16D	1105	110791	122593	110,7	111
6	PAL2	1412	142082	104361	73,5	74
7	SC6s	657	130516	60400	46,3	92
8	PAL5HST	1148	75362	59958	79,6	52
9	SC5s	610	110351	58983	53,5	97
10	SC4s	1045	60363	55586	92,1	53
11	SC15D	1107	78932	51145	64,8	46
12	PAL1ST	824	58834	49176	83,6	60
13	SC5	947	40460	37866	93,6	40
14	SC6	1262	23728	34827	146,8	28
15	PAL6	784	36781	32926	89,5	42
16	SC11	1062	22842	30969	135,6	29
17	SC1	921	34652	25966	74,9	28
18	SC3s	1156	71697	25892	36,1	22
19	SC13H	942	50237	20272	40,4	22
20	SC1s	1209	23452	19863	84,7	16
21	SC-8S	968	36193	18822	52,0	19
22	SC17ST	638	28300	17254	61,0	27
23	SC-9S	568	20222	17019	84,2	30
24	SC9	888	20094	14509	72,2	16
25	SC14DST	596	38610	11772	30,5	20
26	SC7s	723	18754	8247	44,0	11
27	SC7a	648	8877	3638	41,0	6
28	SC12	621	6883	2156	31,3	3
29	SC10	728	4233	1463	34,6	2
30	SC18	649	1429	1297	90,7	2
	TOTAL	27004	1,964,618	1,658,593	84,4	1775
Average (30 Wells)		900				63

The top half of the table shows the accumulated results for all cycles.

Duration of the third cycle was on the average 284 days, steam was injected during 675 days, a partial production increase was observed of 568,863 Bbls (cycle 3) and an accumulated increase of 1658,593 Bbls (cycle 1-3), in other words an increase of 85% on production that the field would have had in primary recovery. The average OSR for wells was 0,25, reaching amounts in some wells higher than 0,5. The percentage injectivity for this first cycle was 96% and the energy injected on the average was 177 million BTU/FT.

CONCLUSIONS

- A history for fluid production and pressure behavior was excellent, clearly representing the behavior of the reservoir.

- The sensitivity for cyclic steam injection parameters for the 28 adjusted wells and the new SC-8S and SC-9S indicates a process of three injection cycles, one injection at 3250 Bbls/day and using an injection pressure of 1500 psi.

- Reservoir response to steam injection is very favorable, showing a better response at the Palermo wells.

- The ratio of oil produced to steam injected into the project was good, and it was within the expected range of 0,25 - 0,5.

- It is estimated that for each steam injection cycle, an approximate 500,000 additional barrels of oil would be recovered as compared to cold production and by primary processes.

- It was observed that reservoir injectivity improves as the number of cycles increase.

- The lab tests showed a decrease in residual oil saturation due to steam displacement the values obtaining values between 13 and 6%.

- Due to the estimated volumes to inject are so high and based on the probability from which the reservoir accept it at working conditions, it has been seen that this volume is much smaller than the one obtained in the laboratory, so it is advisable to previously evaluate in the field the optimal rate of injection by means of injectivity test.

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