AN INTEGRATED STUDY OF THE REJUVENATION OF CAÑADON PERDIDO FIELD (ARGENTINA) BY POLYMER INJECTION

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Abstract. The Cañadon Perdido field (Argentina) is an old field first produced by depletion and recently by waterflood. The reservoir lies in continental fluviatile deposits. The oil viscosity is about 100 cp. The unfavorable water-oil mobility ratio makes the waterflood efficiency low. Thus a polymer solution injection was studied to improve the oil production, considering the favorable temperature and salinity. The preparation of a pilot and the estimation of the economical efficiency of the process are presented.

The paper presents the tasks integrated in the study:

- Laboratory (selection of polymer, measurements of its characteristics inside and outside the reservoir rock).
- Geological and reservoir engineering modelling of the pilot zone, including geostatistical simulation.
- Design of the pilot surface facilities and estimation of costs of a field extension.

The conclusions of the study are:

- A polymer solution is efficient to produce additional oil.
- The reservoir conditions allow to use polyacrylamide, the cheapest polymer.
- If confirmed by the pilot results, polymer injection could be economically attractive.

INTRODUCTION

Though polymer flooding was contemplated as a promising Improved Oil Recovery (IOR) method in the late 70's and early 80's when oil price was high, it is presently not a widely applied recovery process. The present paper shows that, when reservoir conditions are favorable, polymer injection is an economically attractive process.

1. PRESENTATION OF THE FIELD

The Cañadon Perdido field is located in the San Jorge basin, North East of the Province of Chubut, in Argentina, 25 km North of Comodoro Rivadavia city. The field has been operated by YPF since its discovery in 1928.

The oil is rather heavy (22 °API and around 100 cp in reservoir conditions). The reservoir has been produced a long time by depletion, under dissolved gas drainage. A water injection scheme has been recently implemented by YPF S.A.

1.1. Geological Setting

The reservoir series are located in the intracratonic San Jorge Gulf Basin. They belong to the upper Cretaceous (Chubutiano or Campanian-Maastrichtian).

The reservoir is composed of sandy-silty-shally facies representing the Yacimiento El Trebol formation (upper part of Bajo Barreal formation) and corresponding to a fluvial environment. The Tertiary transgressive marine sediments of Salamanca formation are sealing the continental series.

In the Cañadon Perdido field, five stratigraphic layers have been identified. The two uppermost, A and B constitute an upper interval, well separated from a second group composed of C, D and E. The upper interval was first put into production in the 30's. The second deeper interval started producing in the 40's.

The reservoirs are found at a depth of about 900 m below the ground surface. The structure is rather flat, and the series are crossed by NW-SE faults.

1.2. Production history

The upper interval (A, B) was initially put into production through wells drilled only to this interval. Once the wells stopped producing in this interval, the wells were deepened to the second interval (C, D, E). Thus, the production of the two intervals has been performed separately.

Natural depletion under dissolved gas drive is thought to be the main drive mechanism. Some water production was noticed, but no aquifer was found during the drilling in the field, even when exploring deeper horizons. The low level of reservoir pressure at the end of natural depletion does not support the existence of an active aquifer. So the production of water is probably due to the decompression of the less permeable silty rocks communicating with the oil reservoirs, allowed by the long duration of the depletion.

The depletion lasted for about 50 years, until YPF S.A. undertook a rejuvenation of the field by water injection. The existing wells were used according to their mechanical status, some of them being converted into water injectors. This resulted in an irregular pattern of injection production. Due to the viscosity contrast between oil and water, the mobility ratio is around 22. Thus, the water is anticipated to quickly arrive at producing wells, and the oil production should be obtained with high water-cuts.

1.3. Selection of polymer flooding

When looking for IOR methods able to increase the recovery of Cañadon Perdido field, the injection of a polymer solution seemed the more favorable process. The temperature of the reservoir (lower than 60°C) and the low salinity (12 g/l) are compatible with the use of a polymer solution. The water-oil mobility ratio is about 22, thus allowing to reach a unit mobility ratio with a reasonable concentration. The experience coming from previous application of polymer flooding [1-3], was also a support for choosing this process.

Polymer flooding is a way to improve the oil recovery, by modifying the displacement efficiency. Polymer does not decrease the residual oil saturation. But, by correcting the unfavorable water-oil mobility ratio, the polymer solution stiffens the water-oil front, improves the volumetric sweep efficiency and thus it accelerates the production of oil, and makes it more profitable.

2. PREPARATION OF THE PILOT

Once the use of polymer flooding as an IOR process for Cañadon Perdido field was chosen, the study of a pilot was launched. This study was composed of different tasks as follows:

- Selection of a pilot area
- Gathering of geological and engineering data for the wells of the pilot area.
- Laboratory:
  - In vitro selection of a polymer.
  - Injection of polymer solution in reservoir rock samples.
- Geology: building of a geological model of the pilot area.
- Reservoir engineering: building and validation of a model of the pilot area, and determination of size and concentration of the slug of polymer solution to be injected.
- Preparation of surface facilities for polymer injection: conceptual design and estimation of cost.
- Evaluation of cost for the pilot, and for the additional oil produced in case of a field extension.

3. SELECTION OF PILOT AREA

The location of the pilot was chosen in an area of past good production, far enough from faults. Four existing wells 148, 140, 232, 152 are to be used for the pilot (figure 1). Two wells (153 and 231) are abandoned. A new well has to be drilled in the center of the pilot area in order to obtain a five-spot pattern. The average distance between injecting and producing wells is 150 m for the pilot.

To obtain a confined pilot, the four existing wells will inject the polymer solution, while the central well will be a producer. The confinement of the pilot enables to determine the polymer flood efficiency.

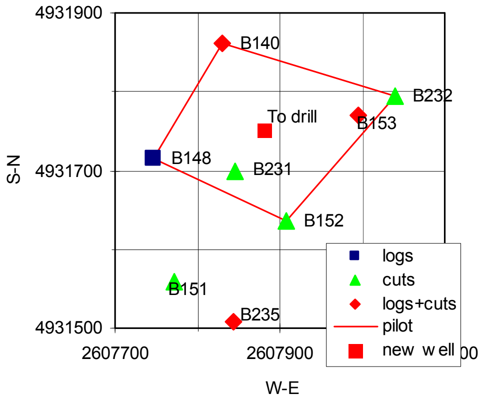

Figure 1 - Pilot Configuration

The reservoir is made of different sequences named A, B, C, D, and E. A commingled polymer flooding in these different units would make impossible to assess exactly the efficiency of polymer flood. Thus, the pilot polymer injection will be undertaken in the group of units C, D and E, as these units appear to be not sufficiently separated to be considered as independent.

4. LABORATORY EXPERIMENTS

4.1. In vitro selection of polymer

This step had for goal to verify :

- The stability of the polymer dissolved in injection water in surface facilities conditions (30°C) and at reservoir temperature (54°C).
- The ability of injection water to be a good solvent for the different polymers. This check was done by the evaluation of both the intrinsic viscosity which determine macromolecule expansion, and the Huggins constant k' (at 30°C and at 54°C) characterizing macromolecules interactions.
- The variations of viscosity versus polymer concentration.

Two types of water for preparing the solution were investigated: the first (water W1) is a water coming from a central production center gathering waters from different fields of the area, the second is the water presently produced on a part of the field (W2). The total salinity is quite the same for both waters, but W1 contains more calcium (see Table 1).

Table 1 - Water composition

SALT	CONCENTRATION (g/L)	
	WATER W1	WATER 2
NaCl	8.890	11.02
$CaCl_2,2H_2O$	4.386	1.088
Na_2SO_4	0.071	0.0457
$gCl_2,6H_2O$	0.050	0.1104
NaN_3	0.250	0.250
TDS	12.56	12.22
pH	6.70	6.80

Three polymers have been tested. They are :

- sulfonated polyacrylamide (SPAM),
- hydrolysed polyacrylamide (HPAM)
- terpolymer type hydrolysed polyacrylamide/sulfonated polyacrylamide (SHPAM).

Their main characteristics are given in the following table.

Table 2 - Polymer characteristics

	SPAM	HPAM	SHPAM
Molecular weight (dalton)	**$8\text{-}10.10^6$**	**15.10^6**	**$8\text{-}10.10^6$**
Anionicity (%)	**27**	**27.5**	**25**
Active product (%)	**90**	**90**	**92.5**

The polymer stability at reservoir temperature was determined with the different waters in the presence or not of dissolved oxygen, by checking the viscosity of the solutions several weeks after preparation. A good stability was obtained for all products.

The evaluation of the intrinsic viscosity, and of the Huggins constant k' showed that both waters were good solvents for all polymers.

Finally, the curves of relative viscosity of the polymer solutions in the newtonian regime were measured. Figure 2 shows the results for the polyacrylamide. The conclusions were:

- the water W2 is a better solvent
- HPAM can give a higher viscosity than SPAM or HSPAM at the same concentration in the same water.

The lower cost of HPAM and its excellent behavior with injection water allows to select it.

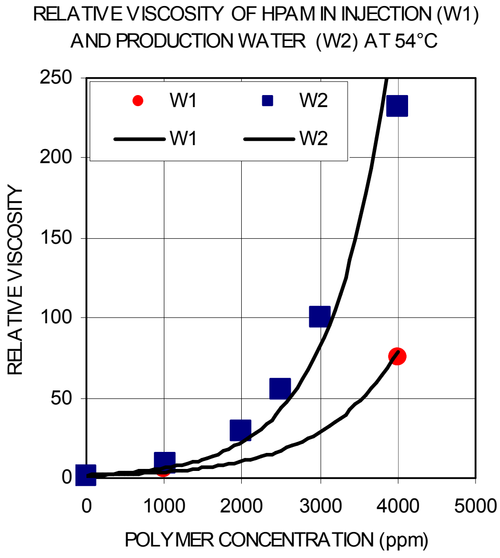

Figure 2 - Polymer relative viscosity

4.2. Core floods

Core flow experiments were carried out to determine :

- The rheology of the polymer solutions in reservoir cores, as a function of polymer concentration (taking into account the polymer adsorption on the rock and the depletion layer effect),

- The adsorption at pore wall surface as well as at water-oil interface.

The first core flow was aimed at measuring the adsorption on mineral surface and the rheology of the polymer solution in the absence of oil. A polymer solution was injected at low concentration (400 ppm) in a plug having a good permeability (k=1043 md) previously saturated with the water W2, at reservoir temperature, to determine the adsorption level onto pore wall surface. Then, alternate injections of polymer (at increasing polymer concentrations) and water slugs were carried out to measure both mobility reduction Rm (ratio of pressure drop during polymer solution flow to pressure drop during brine flow at the same rate without polymer adsorption) and permeability reduction Rk (reduction of core permeability due to polymer adsorption). This experiment showed that the adsorption level is relatively small (A=25 μg/g). The permeability reduction is about 2, and the mobility reduction is slightly lower than the relative permeability.

The second core flow was aimed at measuring the adsorption on mineral surface and the rheology versus polymer concentration in presence of residual oil. A polymer solution was injected in a a good permeability core at residual oil saturation to determine Rm and Rk and to know if polymer get adsorbed at the water-oil interface. This experiment showed that the adsorption level is similar to that found in the absence of oil.

5. GEOLOGY AND RESERVOIR ENGINEERING

5.1. Geological model

To obtain a model representative of the reservoir architecture, the building of a geostatistical based model was undertaken. First a simulation in terms of lithofacies is performed, and this simulation is translated in terms of petrophysical characteristics and then is upscaled to a fluid flow model. In fluviatile deposits, the correlation of sequences is possible, but the correlation of individual sands is quite impossible. A geostatistical model allows to depict the geometry of sands more realistically than the use of cartographic methods interpolating petrophysical parameters between wells. Thus an analysis in terms of lithofacies was performed on well data.

A description of lithofacies was available for a core taken from a well drilled recently in the periphery of the field, as well as log measured in the same well. Thus the first work was to relate lithofacies data to log data, to examine the feasibility of detecting lithofacies information from the logs available on most wells (SP and resistivity). This investigation was performed with the software package EasyTrace, which allows to perform this facies determination. Two modes are available:

- Supervised facies determination: when both core and log are available for the same wells, the package detects which log parameters are the best to recover the same facies determination than the core. Then these criteria may be used for wells having only logs to obtain a facies description.
- Non-supervised facies determination: when only logs are available, the package produces a facies determination by a cluster analysis method.

For the present case, the supervised analysis proved to be able to predict the lithofacies in the wells. The description of all logged wells in lithofacies was thus obtained.

The following step consists in choosing some reference level to define the surface parallely to which the correlation frame will be organized. This horizon, called reference horizon, is crucial to realistically restore the geological coherency of the series to simulate. Here the base of the overlying Tertiary transgressive marine formation has been chosen. Then vertical proportions curves (VPC) were computed. A vertical proportion curve shows the average percentage of a lithofacies computed from well data versus the vertical distance to the reference horizon. Stacking the vertical proportion curves of all lithofacies gives a graph with the percentages of facies along the X axis, and the vertical distance to the horizontal reference horizon along the Y axis. The vertical proportion curves allow a rapid check of the vertical organization of lithofacies, to ensure it is compatible with the geologist's conceptual model. Thus these curves are a very powerful sedimentological analysis tool. They are also required as input of the geostatistical simulations. The examination of the VPC confirmed the stratigraphic scheme previously defined, and led to the elaboration of two units: one grouping the stratigraphic layers A and B, the second grouping the stratigraphic layers C, D and E.

For each unit, the calculation of experimental variograms of lithofacies was performed. The variogram is a mathematical function expressing the spatial correlation for a given parameter. The experimental variograms of the different lithofacies were fitted by the truncation of a gaussian continuous model [5]with the following parameters:

- Upper part (intervals A and B)
  - anisotropic horizontal variograms
  - vertical range: 4 m
  - horizontal range for 135° azimuth: 200 m
  - horizontal range for 45° azimuth: 400 m
- Lower part (intervals C, D and E):
  - isotropic horizontal variograms
  - vertical range: 4 m
  - horizontal range: 400 m

Once the reference level, the VPC and variograms of the two parts are defined, the geostatistical simulation in lithofacies can be run. The petrophysical measurement available with the core allowed to choose a value of porosity and permeability for each lithofacies. Thus a highly detailed model in petrophysical values is available at the end of this phase. The chosen grid for this fine geological model had cells of 20 m x 20 m x 1m. The area modelized corresponds to the pilot itself and to the surrounding wells.

5.2. Reservoir model

To obtain a reservoir model for evaluating the polymer injection, one must upscale the geological model. The flow model grid has been chosen with 60 m x 60 m horizontal cells in the periphery of the model and with a local refinement corresponding to the original 20 m x 20 m geological cells in the center area where is the pilot. In the vertical direction, 9 layers corresponding to the five sandy sequences A to E and to the shally intervals between them have been considered.

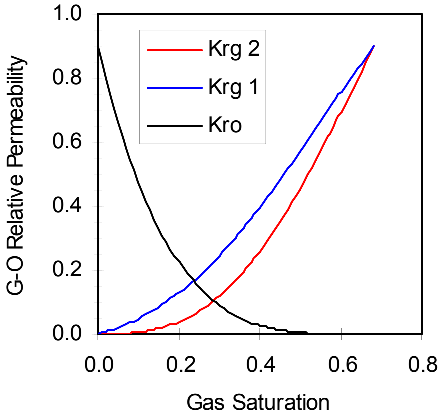

Figure 3 - Oil-Gas Relative Permeability Curves

The first step consisted in validating the model obtained by upscaling. Oil production was well measured in the past, but this was not the case of the gas production which was flared. The gas-oil relative permeability was not precisely known. Thus the analytical model of Corey [3] was used, allowing to change the gas curve by modifying a single parameter (Figure 3). The oil production and the pressure at end of depletion were matched with the curve Krg2 of Figure 3. Thus the reservoir model was considered as compatible with the available data. The average oil recovery factor was about 15 % at the end of depletion.

5.3. Investigation of polymer flooding

Once validated, the reservoir model was used to investigate the efficiency of polymer flooding in the pilot. The water-oil relative permeability (Figure 4) shows a strong wettability to water, with a maximum relative permeability to water about 0.1. To reach a mobility ratio of 1 between oil and the injected water, a polymer solution containing 2000 ppm should be used.

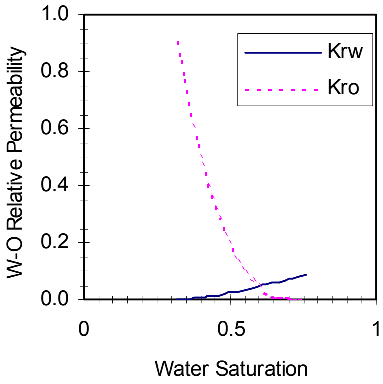

Figure 4 - Oil-Water Relative Permeability Curves

Several cases were studied:

- A base case with water injection.
- Cases of polymer solution flooding, after a short period of water injection. The size (0.1, 0.2, 0.3 or 0.4 pilot Pore Volume or PV) and the concentration (2000 or 1500 ppm) of the slugs have been varied. A 2000 ppm solution would allow to get a mobility ratio of 1, but with higher pressure drops at wells and in the reservoir than a less concentrated solution. After the slug, mere water is injected.

For the case of mere water injection, the injection rate was varied between a value representing the present average conditions, and a theoretical case considering that injection and production could be the highest possible. The last case represents a doubling of injection rate, thus a doubling of pumping and water handling capacities. Due to the high mobility ratio, this production would be obtained with a very high water-cut. Thus this second water injection case should be regarded as a rather theoretical one, aimed at maximizing the estimation of recovery possible with water. The final additional recovery factor after 10 years of mere water injection was 13 % IOIP for the first injection case and 16 % IOIP for the maximum injection case.

When injecting the polymer solutions, the best case appears to be that of a slug of 0.4 PV with a 1500 ppm concentration. The additional recovery factor over the first case of water injection is 14 % IOIP. The total recovery factor is 42 % IOIP in the pilot area, including the primary production and the waterflood production. If compared to the case of maximum water injection, the additional recovery factor due to the polymer is still 11 % IOIP.

If expressed in volume of oil recovered per unit mass of injected polymer, the efficiency of the process is about 1 additional bbl of oil per kilogram of polymer.

The case of 0.3 PV slug with a 2000 ppm concentration gives a slightly lower recovery factor. The mass of injected polymer is the same in the two cases. But the longer slug (0.4 PV) and the decrease of mobility contrast between chase water and polymer slug is favorable to the lowest concentration slug.

The reservoir model including the wells surrounding the pilot area, it is also possible to estimate the total volume of extra oil produced in the neighboring wells influenced by the pilot injectors. Globally, the extra oil should compensate the major part of the expenses devoted to the pilot.

6. SURFACE FACILITIES

6.1. Pilot

Specific surface facilities must be devoted to the pilot. Polymer powder is used. A polymer solution at high concentration (5000 ppm) is prepared by dissolution of the polymer powder, followed by maturation. The injection of a solution at the required concentration is obtained by mixing the high concentration solution after filtration with water, and compressing the resulting solution with low shear pumps to avoid mechanical degradation of polymer molecules.

The devices necessary to perform the operations of dissolution, maturation, filtration, mixing, injection, are assembled in skids, which are mounted in factory, then carried to the pilot location and assembled there. The skids may eventually be used again for other pilot operations.

6.2. Field extension

The same type of surface facilities should be installed for a field extension. They would include dissolution, maturation, filtering, mixing and injecting devices. The difference with the pilot case would be the size effect, making the cost per injected m^3/d lower than for pilot operations.

A rough estimate of the cost of the additional oil can be done on the basis of the results of the pilot model. For an efficiency of 1 bbl/kg of polymer, and with the estimate of the surfaces facilities cost for a field extension, the cost of additional oil directly due to the polymer should be around 5 US $/bbl. This calculation should be refined considering all economic parameters related to the producing country and to the operating company in order to obtain an estimate of the project net present value. But the figure of 5 US $/bbl shows that the project should be considered for oil prices larger than 15 $/bbl.

7. CONCLUSIONS

In the present study, we have integrated the different tasks related to the preparation of an IOR pilot: selection of polymer injection, selection of the product to inject, preparation of a geological model and of a reservoir model to evaluate the efficiency, evaluation of cost of surface facilities.

The favorable reservoirs conditions (low temperature, availability of a water with a low salinity and a low calcium content) allowed to select polyacrylamide as the active product. HPAM is efficient and relatively cheap, compared to other products (SPAM) which would have been necessary in less favorable conditions.

We recommend to use a 0.4 PV slug at 1500 ppm of HPAM, which should allow to obtain an additional oil recovery factor of 14 % IOIP compared to mere water injection. The benefice of polymer injection is mainly an acceleration of the oil production, which allows to produce more quickly at a lower water-cut.

The estimation of the economics of the polymer injection looks attractive. For the pilot operation, the total incremental oil should compensate the major part of the expenses. An estimation of the cost of the additional produced oil for an extension of the polymer process to the field leads to a cost of 5 US $/bbl. The polymer solution injection is thus an attractive oil recovery process in the Cañadon Perdido field.

When reservoir conditions are favorable (moderate temperature, salinity, and divalent ion content) while the displacement mobility ratio is unfavorable, the polymer flooding is a process that deserve to be carefully considered for increasing the oil production and the value of the reservoir.

ACKNOWLEDGEMENTS

The authors wish to thank the management of YPF S.A. for permission to present this field case.

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