Water Flooding Combined With Infill Drilling at the Helvetian Strâmbu Field

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ABSTRACT

The Strâmbu reservoir is located in ten strata caps of the Helvetian period, transgressively and unconformably overlying the Oligocene, with dips ranging from 40° on the west to 10° on the east.

The reservoir rock, of the granular and predominantly psammitic type, has a pronounced inhomogeneity; oil density is 824 kg/m³ (standard conditions), and oil viscosity is 16 mPa.s (initial reservoir conditions).

Production started in 1952 and until 1976 it was achieved exclusively under primary recovery. By the end of 1976, a high degree of energy depletion was noticed, with a recovery of only 15.2%.

Waterflooding started as an experiment in December 1976 and it was gradually extended, yielding good results.

It was followed by the extension to a commercial scale by waterflooding and infill drilling.

Location of injection wells was designed in such a way as to comprise as much reservoir volume as possible by water displacement.

The combined effect of water injection, and at the same time, of infill drilling led to an increase of oil production from 120 t/d in December 1976 to a maximum of 750 t/d in May 1985. At the beginning of 1995 recovery was 30% and incremental oil production owing to the combined effect of water injection and infill drilling stood for 1,833,000 t.

An ultimate recovery of 34% is estimated.

1. INTRODUCTION

Seismic surveys led to the discovery in 1950, in the south-eastern part of the Getic Depression of some important structures consisting of rocks with good reservoir properties. Among these, hydrocarbon reservoirs belonging to the Helvetian and Meotian were outlined on the Strâmbu structure (Fig.1) developed on

the east-west direction, with a length of 3,000 m and a width of 1,500 m, [1].

From among the numerous reservoirs produced by water injection in Romania starting from 1950, this case is interesting, owing to the existence of superimposed productive complexes, produced under primary recovery by commingled production, and not from each individual formation, to the rapid and favorable response to water injection inside the oil saturated zone and to the favorable effect of combined water injection and infill drilling.

The purpose of this article is to outline the main stages of the development of this reservoir, and their respective results.

2. GEOLOGY

The most important reservoir belonging to the Strâmbu structure (Fig.1), is developed in the Helvetian with a thickness comprised between 300 m and 350 m. The Helvetian is of the pseudomassif type with bottom water, the depth of the initial oil/water contact being 1,140 m.s.s., [10]. The angular unconformity at the Meotian-Helvetian limit and the F₁ and F₂ fault system led to the creation of some tectonic and stratigraphic traps which enabled the Strâmbu reservoir to be formed within the Helvetian porous-permeable deposits.

2.1. STRATIGRAPHY

The Strâmbu structure developed in a sedimentary basin with the Oligocene formation, with a pronounced tectonics, as a subbase, the sediments being deposited over this relief, and affected by the orogenic movements during the Neogene.

The important volume of cores that was available allowed the petrographic, mineralogical and geochemical correlation of all encountered formations, starting with the Oligocene and ending with the Meotian, [1,2].

Fig. 1 - Structural map at Me/He limit
1 : 20000

The development of the sedimentary basin included the following five periods:

a) the Paleogene period - The core analyses permitted the outlining of Oligocene deposits, represented by fine grained and tight black clays, and partially, by dense shales, with fine mica grains, and light gray, fine grained sand intercalations. The orogenic movements markedly affected the Eocene and Oligocene formations, submitting them to intense episodes of plication and rupture, and breaking them into numerous fault blocks, with strata dips up to 70°...80° (Fig. 2).

b) the Oligocene-Helvetian period - The end of the Paleogene is characterized by an ample regression accompanied by the emergence of Oligocene formations and then by their erosion as a result of the Savic orogeny, determining the occurrence of a stratigraphic gap to the beginning of the Helvetian, [1].

c) the Helvetian period - The Neogene transgression led to the extension of the sea basin and the resumption of the sedimentation process, the Helvetian deposits overlying transgressively and unconformably the Oligocene. Petrographic determinations on over 94 intervals from which cores were taken, revealed a great variety of rocks which give the Helvetian a complex and

inhomogeneous character. Intercalations and thinning-outs, facies variations are frequently encountered, pointing to the fact that sedimentation took place in a shallow sea area, more exposed to the action of sea currents. Over the entire duration of the Helvetian, the formations suffered folding movements, the faults at the level of the Oligocene being reactivated and affecting the entire pile. Dips at the level of the Helvetian are comprised between 10° and 40°. Brown, fine grained sands with scarce, tight gray marls, and brown sandstones intercalations with calcite cement are predominant, [2]. Brown, tight, marls, with fine grained mica, and fine grained sandstones are frequently encountered, hosting a Helvetian microfauna represented by *Globotruncana linneana* (d'Orb), *Lenticulina macrodisca* (Reuss), *Gyroidina neosoldanii* (Brotzen) and *Lagena laevis* (Montagu), [1].

During the Helvetian, the western part of the basin suffered a gradual emergence movement, concurrently with a downthrow of the eastern part, which influenced sedimentation, the basin waters withdrawing by the end of the period.

The result was the occurrence of a sedimentary gap which lasted until the beginning of the Pliocene, [3, 4].

Fig. 2 - Depth seismic section and typical electric log
A - A' Seismic Profile

Fig. 3 - Cross section

d) the Helvetian-Meotian period - The geophysical data interpretation led to the separation of 10 pay zones, numbered from 7 (the oldest) to 16 (the latest) (Fig. 3). This period is characterized by the emergence of the formations from the sea environment and their exposure to an erosion process until the beginning of the Pliocene, during which a new transgression took place, [3, 4].

e) the Pliocene period - The sedimentary basin extended its area beginning with the Pliocene, entirely developed and overlying transgressively and unconformably the Helvetian deposits. The Meotian is characterized by gray, fine grained sands, alternating with gray marls, [1, 2]. The Pontian is developed in an exclusively marly facies, with a continuous sedimentation. The Dacian and Helvetian are characterized by coarse grained sands, marls and thin coal intercalations. The Quaternary completed the sedimentation cycle, being represented by alluvial loess and terrace formations. During this period, the plication episodes had lower intensities, the Meotian strata having dips comprised between 5° and 12° (Fig. 4).

Fig. 4 - Tectonic scheme

2.2. TECTONICS

Starting with the Paleogene, the Strâmbu structure developed as regards the sedimentation area, the oldest known formations belonging to the Oligocene. Those have a pronounced tectonics and are broken into fault blocks, by two fault systems, [1, 2, 3, 4]:

- F_1 and F_2 system, with an approximate west-east orientation;
- F_3 and F_4 system, with a north-south orientation.

Orogenic movements (Savic, at the end of the Paleogene; old Stirical, Intra-Burdigalian and new Stirical, Intra-Badenian) reactivated the two fault systems submitting the formations to a folding process. The resulting dips are designated in Fig. 1, [1].

Block II, located north of fault F_1 , and blocks III and IV, located south of fault F_2 (Fig. 1) were subject to several positive movements, being onshore areas until the Pliocene when they became offshore areas as a result of the basin extension through transgression. On the other hand, the $F_1 - F_2$ system determined the collapse of the block I (Fig. 4) at the beginning of the Miocene and the formation of a graben, where, during the Helvetian, marine conditions developed, marked by two different evolutions:

a) the eastern area was submitted to a subsidence movement and,

b) the western area was submitted to an emergence movement.

F_1 and F_2 fault slips are comprised between 50 m and 100 m.

The Pliocene was affected to a lesser extent by the succeeding orogenic movements (Fig. 2) resulting in a quasi-horizontal Meotian, with dips between 5° and 12° , with a practically complete structural arrangement.

3. PHYSICAL PARAMETERS

The reservoir rock consists of poorly consolidated sand or sandstones layers, with a coarse, medium or fine grain, reduced by erosion and containing marly or marly-sandy intercalations, with thicknesses comprised between 1 m and 5 m, appearing as lenses.

The porous-permeable strata were grouped into complexes, separated by marly or marly-sandy intercalations, discontinuous ones. Besides this physical reservoir characteristic, and bearing in mind that production was commingled, by opening most of productive complexes, in all wells, one can get the image of the existing situation in 1976 [5], i.e. the image of a single reservoir, not affected by faults. There are exceptions to this image, caused by several new wells drilled after commencement of water injection which produced by natural flowing, with important flow rates and pressures, due to their marginal position.

The geophysical investigations as well as the core analysis results led to the idea of a pseudomassif type reservoir (with bottom water).

The inhomogeneity coefficients have, according to Dijkstra-Parsons, a value of 0.69/0.81, and according to Lorenz, of 0.53/0.56 for permeabilities perpendicular/parallel to the stratification.

The reservoir storing capacity*) has the highest values in the western part of the reservoir and has a tendency to decrease from the south-west to the north-east.

The average values of the main physical parameters of the rock and contained fluids are given in Table 1.

Table 1
AVERAGE VALUES OF THE MAIN PHYSICAL
PARAMETERS

Depth	m	1400
	ft	4593
Temperature	$^\circ\text{C}$	60
	$^\circ\text{F}$	140
Pressure	bar	137
	psi	1987
- initial reservoir	bar	61
	psi	882
- current reservoir	bar	117
	psi	1697
Effective thickness	m	32
	ft	105
Porosity	%	25.4
Absolute permeability	μm^2	0.419
	mD	419
- parallel with the layer	μm^2	0.402
	mD	402
- perpendicular to the layer	μm^2	0.6
	mD	60
Interstitial water saturation	%	23
Oil saturation		
- initial	%	77
- current	%	51
Oil gravity	kg/m^3	824
	$^\circ\text{API}$	40
(standard conditions)		
Relative gas density (air = 1)		0.6
Oil viscosity	mPa·s	16
	cP	16
(initial reservoir conditions)		
Solution ratio	Sm^3/m^3	58
	Ft^3/Bbl	325
(initial reservoir conditions)		
Oil volume factor		
		1.179
(initial reservoir conditions)		

4. PRODUCTION PERFORMANCE

4.1. PRODUCTION BY PRIMARY RECOVERY

Production started in 1952, and the maximum number of wells was 63, in 1957 (Fig. 5 g).

In most cases, the wells produced initially by natural flowing, over time intervals comprised between 3 months and 3 years, with flow rates of 15 t/d to 30 t/d, which rapidly decreased calling for proceeding to production by pumping.

*) Porosity times oil saturation

In most cases wells were initially opened over short intervals at the base of the productive complexes' pile, during the first production years, with other intervals added, in stages, leading to perforated intervals on the western part of the reservoir, which summed up, measured over 40 m within the same well (Fig 3). Difficulties related to correlation over long distances and the rush for an important immediate production led to a commingled exploitation, not selectively centered on productive complexes (Fig.3), [5, 6].

Production was obtained under dissolved gas drive. It was to be expected to get a reduced primary recovery. 15 years after production commencement, the pay zone was extended to the west (Fig. 1), with an initially unknown area, thus obtaining, during continuation of production, a group of wells, within this western extension, with pressures below initial reservoir pressure, but with oil flow rates markedly superior to those comprised in the area where production started in 1952 (Table 2), [7].

Table 2
WELL DISTRIBUTION ACCORDING TO CLASSES
OF OIL FLOW RATES

Class of Oil Flow Rate, t/d, w	Old Area*		New Area** (Western Extension)	
	No. of Wells	%	No. of Wells	%
0...1	23	56	1	9,1
1...2	8	19,5	1	9,1
2...3	4	9,8	2	18,1
3...5	4	9,8	2	18,1
5...8	2	4,9	-	-
8...13	-	-	5	45,6

*) 41 wells with a total production of 69.4 t/d or an average production of 1.7 t/d, well.

**) 11 wells with a total production of 45.6 t/d or an average production of 4.1 t/d, well.

During the first years of exploitation production increased rapidly, alongside the number of wells, reaching, in 1956, a maximum value of 340,000 t through 61 wells (930 t/d; 15.2 t/d, well; Fig. 5a, 5b, 5g).

Further on, production decreased rapidly, 98,000 t being obtained through 63 wells (268 t/d; 4.3 t/d, well) in 1961, and 42,000 t through 49 wells (115 t/d; 2.3 t/d, well) in 1968. Starting with 1969 a reversal in the production trend was witnessed brought about by bringing in the 11 wells in the western extension (Fig. 1, 5a, 5b). In 1976, the year in which the design of the exploitation of the entire reservoir was reconsidered, production amounted to 48.800 t through 52 wells (133 t/d; 2.6 t/d, well), [5].

Watercut increased slowly reaching 20%, in 1976 (Fig. 5d).

Fig. 5 - Production history

The gas-oil ratio reached the value of $280 \text{ Sm}^3/\text{m}^3$ in 1958, then it decreased and remained $150 \text{ Sm}^3/\text{m}^3$ until 1968 when it started increasing again after commencement of production from the western extension, after which it reached a maximum of $300 \text{ Sm}^3/\text{m}^3$ in 1977, followed by a rapid decrease (Fig. 5h). By the end of 1976, the production of the entire reservoir had reached 120 t/d (Fig. 5a), the production of an average well being 2.3 t/d (Fig. 5b), the produced oil cumulative 2,440,000 t (Fig. 5e), and the recovery, 15.2% (Fig. 5f).

Fig. 6 - Reservoir pressure vs. time

By reviewing the graphs shown in Fig. 5 it can be inferred that this is a normal behaviour for a reservoir produced under dissolved gas drive.

The evaluations made by the end of 1976, [5] pointed to the fact that:

- recovery had reached 15.2% after about 25 years of production by exclusively primary recovery;

- production continued to slowly decrease and, provided the number of producers remains constant, by 2005, about 54 t/d will be obtained, with a recovery of 20.2%;

- though the average daily flow rate of a well will still have a value of about 1 t/d, well, production will be performed with major difficulties and low profitability due to a poor production and to the expenditures for keeping under operation conditions wells several decades old;

- the actual number of producers was likely to decrease continuously, accompanied by a pronounced decrease in the daily production alongside an increase of the production life.

Furthermore, it should be borne in mind that the estimated value of about 1 t/d, well of the average flow rate predicted for 2005 was mostly due to the group of 11 new wells brought in 15 years later, and that after 30 years, the average flow rate of a well (an old one) from the group of 41 wells (Table 2) would be much below 1 t/d, well, the very existence of those wells being most unlikely.

Under these circumstances, the attainment of the ultimate recovery under primary recovery, as previously assumed had low chances of being achieved, and the production economic efficiency decreased dramatically. As mentioned in this study [5], the reservoir, by its physical parameters and its depletion stage at that

moment, was a good candidate for experimental water flooding.

Prior to commencement of water flooding, watercut had ranged between 15% and 30% (Fig. 5d).

4.2. WATERFLOODING EXPERIMENT

In general, it is recommended that waterflooding be performed selectively, making sure that the producers are open to the layer being injected.

The strict application of this requirement for the Strâmbu Helvetian would have meant either the existence of a separate network of wells (injection; production) for each complex, or a very long production life with a single network, to be withdrawn from bottom to top. Economically, in both cases, production was very close to the unprofitability zone.

For this particular reservoir made of strata caps, peripheral water injection line (below the oil-water contact):

- would have a favorable effect only on an area close to the water injection interval of each complex;

- would suppose long time intervals until the appearance of the effect, due to the large volume of the aquiferous basin;

- would not allow a separate monitoring, by complexes, of the effect, due to the discontinuities of marly separations and to the opening of almost all wells into all productive complexes.

The injection exclusively inside the oil saturated zone would suppose:

- the risk of water channeling towards the downstream producers especially in the western part of the reservoir, where dips have values up to 35° ;

- a markedly different volumetric displacement efficiency between the wells upstream and downstream of the injecting well;

- the impossibility to monitor separately, by individual complexes, the effect of water injection, due to the discontinuities of the marly separations and opening of almost all wells in all productive intervals.

Water injection, inside the oil saturated zone, over the entire productive pile, as well as on a peripheral line, by opening also the injectors under the oil-water contact, would determine oil displacement by water involving a much larger reservoir volume, but at the same time would reduce the possibilities for rapid action related to production control.

In view of obtaining basic information in connection with receptivity, effect on production, response time, actual channeling risk, it was decided to perform an experimental stage of water injection. Each central well of an injection pattern (Fig. 1, 7) was to be opened to all perforated complexes for all output wells of the respective pattern. Thus it was hoped to be able to notice the difference in effect between producers located upstream or downstream of the injector, as well as the possible influence on wells located outside the pattern. It was estimated that, in the case of a successful water injection experiment, and of commercial production by this method, oil saturation would then be reduced from

Fig. 7 - Production behaviour by waterflooding, of the four experimental patterns.

0.61, which was the average value existing by the end of 1976 [5], to 0.46 by the end of the production life, with an ultimate recovery of 34%.

The decision made in 1976, to test water injection was encouraged by the important value of oil saturation at that time (61%), by the low value of daily production (120 t/d, reservoir; 2.3 t/d, well) and of the recovery (15.2%), by the existence of 49 wells under a good technical condition and of some idle wells which could be used for injection, by the good water receptivity of the Helvetian, by the favorable value of the mobilities ratio and by the possibility to obtain and treat the water necessary for injection, by the important value of the original oil in place, by the poor value of the ultimate recovery to be achieved under dissolved gas drive and by the long duration in which the latter could have been achieved. It was estimated that in the case of commencement of commercial production by water injection the ultimate recovery would be superior by a minimum of 10% to the calculated value for production

under dissolved gas drive.

The unfavorable factors were the pronounced inhomogeneity of the reservoir, the uneven energy exhaustion of various complexes or areas of the latter, which increased the risk of channeling of injected water, especially in areas with high dips, and the possibility of stimulating sand encroachment. For these reasons, in the case of commencement of commercial production by water injection, it was recommended to proceed carefully to such an extension, by strictly limiting the liquid flow rates of the producers to values slightly lower than the maximum admitted ones, even with the risk of entailing a slight increase of the production life. This recommendation was admitted, as abandoning a well would have meant losses either due to leaving a reservoir area undrained by water, or to the need to drill a replacement well.

Experimental water injection was achieved using 4 patterns (Fig. 1, 7) starting with December 1976 and January 1977. As expected, injection flow rates were

Fig. 8 - Waterflooding history

comprised between 100 $\text{m}^3/\text{d, well}$ and 200 $\text{m}^3/\text{d, well}$, and the effect of injection over oil production became obvious first by stopping the decline and then by increasing the oil flow rate (Fig. 7), [6, 7].

Owing to the very good reservoir receptivity, the gradual transition to the commercial production stage by waterflooding was commenced even before obtaining the maximum effect on production, attributable to waterflooding within the 4 patterns, [7].

4.3. COMMERCIAL PRODUCTION BY WATERFLOODING

In view of the gradual transition to commercial production by waterflooding, it was necessary to design and then to achieve the networks of injection or production wells. Well location was established taking into account:

- the need to inject water into each productive complex starting from the uppermost part in the most favorable positions to displace oil in the most efficient and uniform manner;
- the need to have, within each complex, sufficient producers around an injector in an adequate arrangement to minimize as much as possible the risk to leave behind areas unexposed to the effect of injection;
- the need to fully exploit the operating wells and to operate again some of the previously abandoned wells;
- the relief of the basin and the oil production of the wells at that moment.

The generally reduced reservoir dip, the lack of some water-oil contacts of a considerable length, and the production method previously used (the opening of practically all productive intervals, which was the case with all wells) determined the application of an internal injection line at the commencement of waterflooding, over the entire productive section, and into the first complex below the oil-water contact so as to include production from the area comprised between this contact and the first row of producers above it. It was supposed that the flow of the injected water directly into the oil saturated area of each complex would cause a more rapid response of the producers; the oil-water contact would start to rise from the very beginning of the injection process. During the first stage, the new producers were to be opened selectively, by complexes, from bottom to top. An important increase of production at the level of the entire reservoir was recorded (Fig. 5a, 5b) with a short response time and no significant channeling, [8, 9].

The values of the injection flow rates were permanently monitored and correlated with the behaviour of the producers from the influence area. Thus, situations were noticed and corrected, such as wells within watercut classes of over 60% which had either a low gross flow rate (up to 15 $\text{m}^3/\text{d, well}$) and a net flow rate below the average reservoir value, or a high gross flow rate (40 $\text{m}^3/\text{d, w}$ to 60 $\text{m}^3/\text{d, w}$) and an equally high net flow rate (over 8 t/d, w). Those facts outlined the need to make slight changes in the values of the injection flow rates, or the calculated production rates, as necessary, to

periodically reconsider the network of injection or production wells; and to differentiate three classes of injection flow rate depending on the effective thickness of the area under consideration:

- 120 m³/d, w in the western area where the effective thickness is comprised between 40 m and 60 m;
- 80 m³/d, w in the central area, where the effective thickness is comprised between 20 m and 40 m;
- 50 m³/d, w in the eastern area, where the effective thickness is comprised between 10 m and 20 m.

During the development of the reservoir a well may be turned from a "producer" into an "injector" when watercut reaches high values.

A ratio above the unit between the volume of injected water and the total volume of produced fluids was sought in order to start partial restoration of the reservoir pressure (Fig. 6).

In the period between the beginning of 1978 and the end of 1981 the water injection flow rate was basically maintained constant at 800 m³/d through 8 wells (Fig. 8a, 8b, 8c) whereas the production of an average well remained at about 3 t/d, well (Fig. 5b) and the production from the entire reservoir increased from 120 t/d through 40 wells, to 180 t/d through 60 wells (Fig. 5a, 5g).

From the very beginning of 1982, the combined effect of waterflooding and infill drilling became obvious. The oil production of the entire reservoir increased, [7, 8, 9, 10, 11]:

- by the end of 1982 to 350 t/d through 89 wells

(4.0 t/d, w; Fig. 5a, 5b, 5c, 5g), waterflooding being 3,200 m³/d through 29 wells (110 m³/d, w; Fig. 8b, 8c, 8e);

- by the end of 1983, to 570 t/d through 114 wells (5 t/d, w; (Fig. 5a, 5b, 5c, 5g), waterflooding being 4,000 m³/d through 32 wells (125 m³/d, well; Fig. 8b, 8c, 8e);

- by the end of 1984, to 670 t/d through 166 wells (4 t/d, w); waterflooding being 5,000 m³/d through 45 wells (111 m³/d, w);

- by the middle of 1985, to the maximum value of 750 t/d through 179 wells (4.2 t/d, w), waterflooding being 5,100 m³ through 49 wells (104 m³/d, w);

- by the middle of 1986, to the maximum, stable, value of 750 t/d, but through 205 wells (3.7 t/d, w), waterflooding being 6,200 m³/d through 66 wells (94 m³/d, w).

Further on, oil production steadily decreased:

- 448 t/d by the end of 1988, through 187 wells (2.4 t/d, w), waterflooding being 6,600 m³/d through 86 wells (77 m³/d, w);

- 360 t/d by the end of 1989, through 177 wells (2.0 t/d, w) waterflooding being 6,770 m³/d through 88 wells (77 m³/d, w);

- 314 t/d by the end of 1990 through 152 wells (2.1 t/d, w), waterflooding being 6,705 m³/d through 82 wells (82 m³/d, w);

- 224 t/d by the end of 1992, through 147 wells (1.5 t/d, w), waterflooding being 6,530 m³/d through 75 wells (87 m³/d, w);

Fig. 9 - Incremental production obtained by waterflooding and infill drilling

- (A) Entire reservoir production under PRIMARY, based on the assumption that only the 49 producers existing in December 1976 will continue to produce.
- (B) Entire reservoir production under PRIMARY, based on the 49 producers in December 1976 plus subsequent infill drilled wells.
- (C) Actual production from the entire reservoir, with WATERFLOODING and INFILL DRILLING.

- 213 t/d by the end of 1994, through 150 wells (1.4 t/d, w), waterflooding being 5,230 m³/d through 63 wells (83 m³/d, well).

In Fig. 9 it can be noticed that as compared to the primary production which would have been obtained exclusively from the 49 wells existing in December 1976 (curve A), the incremental production obtained after that date is primarily attributable to water injection (curve C) and secondly to infill drilling (curve B). As of January 1995 the incremental production resulted from the combined effect of water injection and infill drilling was 1,833,000 t oil, with a recovery of 30% (Fig. 10).

Fig. 10 - Comparison between the 1977 predicted oil recovery and the actual oil recovery.

CONCLUSIONS

1. The Strâmbu reservoir is located within ten complexes appearing as strata caps, of the Helvetian age, transgressively and unconformably overlying an Oligocene basin, with dips comprised between 40° on the west and 10° on the east.
2. The reservoir rock has an important degree of inhomogeneity. Oil, has a density of 824 kg/m³ (under standard conditions) and a viscosity of 16 cP (under initial reservoir conditions).
3. Production began in 1952, and for a period of 25 years it was obtained under primary recovery, with a recovery of 15.2% by the end of 1976, when the energy depletion reached an advanced stage.
4. Testing of waterflooding started in December 1976. It was decided to proceed to commercial production by waterflooding.
5. The basic principle of waterflooding consists in:
 - opening of injection wells and waterflooding into all productive complexes and into the first complex located below the oil-water contact;
 - successive opening of new producers from bottom to top, as production ceased in the complex produced at a certain period.
6. Injection wells were located as to ensure oil displacement by water from as much reservoir volume as possible. The producers/injectors ratio is 3:1.

7. In view of production by waterflooding, 251 producers and 18 injectors were drilled.

8. As of January 1, 1995:

- the recovery had reached 30%;
- an incremental production of 621,000 t was obtained owing to infill drilling, and of 1,212,000 t, due to water injection;
- it is estimated that the ultimate recovery will be 34%.

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