HEAVY OIL RECOVERY BY STEAM INJECTION – NUMERICAL SIMULATION ON PRODUCTION STRATEGY

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Abstract. *Heavy-oil fields are usually good candidates to thermal recovery methods. Primary mechanisms of production or water injection do not provide a good efficiency for reservoir drainage due to the high oil viscosity. Steam stimulation's main purpose is to raise reservoir temperature and consequently reduce oil viscosity, increasing oil mobility. Also, gas flow is postponed since less pressure drop is necessary to maintain the same fluid flow conditions. This paper is focused on thermal reservoir stimulation and its evaluation by the simulation standpoint. A synthetic model of an onshore heavy-oil formation (~12 ºAPI; ~500 cp, ~100 MMm3 oil in place) was studied and its characteristics were submitted to a check screening procedure. Simulation was conducted considering three scenarios: a) primary production, b) cyclic stimulation and c) cyclic injection followed by steam drive. A regular five-spot scheme was implemented and well constraints were selected according to technical indications and feasibility. The presented analyses and discussions resulted in significant insights regarding heavy-oil and steam recovery mechanisms such as the fact that heavy oil is mainly produced by contacted volume; cyclic stimulation should be implemented as soon as possible due to temperature influence on oil viscosity and to the reservoir's own drive energy; continuous injection can be useful if heat continuity is established as a consequence of reasonable covering drainage area; and finally that steam stimulation must be implemented firstly on the more productive wells if there are limiting conditions. The important contribution that can be pointed out is the use of numerical simulation as an excellent predictive tool to evaluate production strategy of a heavy-oil field, specifically applying the steam injection mechanism.*

Keywords*: Improved Oil Recovery, Steam Injection, Reservoir Simulation*

1. INTRODUCTION

Traditionally, after primary recovery, water is injected into the reservoir to maintain pore pressure and displace oil toward production wells. Displacing and displaced fluids are not miscible and any chemical or thermodynamic interaction between them or with the rock is present. Since heavy oil tends to be more viscous than conventional oil, the resulting unfavorable mobility ratio ($M > 1$) leads to a low displacement efficiency of water injection process for heavy-oil fields. This is one of the main reasons why heavy-oil fields are technically more difficult to be produced, requiring more investment when compared to conventional oil fields. Consequently, they are usually good candidates for improved recovery techniques.

Heavy-oil viscosity shows expressive reduction with temperature increase, motivating thermal methods application. Among them, steam-based methods have been more successful commercially than others (Thomas, 2008). They have been used for years to recover heavy oil mostly from California (USA), Venezuela and Canada (Nasr and Ayodele, 2005). In Brazil, the cyclic steam injection was introduced in the late seventies, following the discoveries of heavy oil reservoirs in the onshore portion of Sergipe-Alagoas and Potiguar basins. Later on, steam drive was applied. Steam injection was one of the few improved recovery techniques that evolved from pilot to commercial scale in Brazil (Shecaira, 2002). Currently, in addition to the northeast fields, the method has been applied to the onshore Espírito Santo basin, with a special highlight to the Fazenda Alegre field.

Like all other enhanced oil recovery methods, steam injection involves high operational costs. Laboratory tests, numerical simulation and field pilot are among the studies to be carried out for the candidate reservoir. Based on their results, technical and economical viability of the method is verified before implementing the project itself.

According to Abou-Kassem (1995), numerical simulation of thermal recovery methods is still not a standardized procedure and choices must be made at various stages in the implementation of a given solution scheme. For this paper, a synthetic model of an onshore heavy-oil field was developed, using a commercial simulator, and it was submitted to a check steam screening procedure. Once admitted by this procedure, the field production was evaluated under primary recovery, cyclic and continuous steam injection. Cumulative oil production, oil-steam ratio, efficiency of the steam process and efficiency on the anticipation of oil production were the main parameters used in the decision analysis.

The main objective is to verify the screening process for reservoir selection, physical mechanisms and simulation characteristics associated to steam recovery application.

2. BACKGROUND AND THEORETICAL CONCEPTS

2.1. Thermal Recovery Effects and Fluid Properties

Although the main objective of the thermal methods is to raise reservoir temperature to reduce oil viscosity and consequently improve oil mobility, other contributing phenomena may occur due to temperature and pressure increase. The experimental work of Willman *et al.* (1961) shows a quantitative analysis for each mechanism and its influence on the final recovery. The work used laboratory linear cores saturated with specific test oils and water and the high recovery factors obtained are result of this controlled environment. However, the results present interesting conclusions on the relative magnitude of each mechanism. Viscosity reduction and thermal expansion of the oil are the main mechanisms, followed by steam distillation of the lighter fractions in the crude and solvent effect.

Many oil properties show dependence with temperature, such as viscosity, heat capacity, thermal conductivity, density etc. The key parameter for thermal methods is oil viscosity. It falls exponentially with increasing temperature. Figure 1 shows the graphic of kinematic viscosity vs. temperature for some crude oil samples with different API gravities. It can be observed that, at the same temperature, the viscosity of the oil increases with its density and, the higher the viscosity the greater the viscosity reduction for a given temperature increase. So, for the same increase in temperature the reduction of the crude oil viscosity is more evident for heavier crudes. This is why the thermal methods are more suitable for heavy-oil fields than for light-oil fields, where the conventional methods are more cost-effective. On the other hand, if the in situ oil at initial conditions is too heavy (viscosity and density are too high), even a relevant temperature increase cannot turn it mobile. So, there are practical limitations on both extreme values of viscosity.

Regarding the analysis of steam as a heat carrier agent, it is valuable to point out the liquid to vapor phase change properties of the water. Figure 2 shows a plot of the amount of heat (enthalpy) carried by water as a function of pressure. The two-phase region (inside the envelope) where both water and steam coexist is the area of importance in oil field steam operations. One can see that the decrease of latent heat content of steam is larger than the increase of the sensible heat with increasing pressure and temperature. So, if injection pressure of steam is just enough to allow its flow within the reservoir, it will have more heat content than at higher pressure. Another parameter verified in the plot is the steam quality. Higher quality provides higher latent heat content of steam. To summarize, maximum quality and minimum pressure and temperature result on high thermal energy delivered by steam. These are parameters closely associated to reservoir characteristics (depth, initial pressure and temperature) and steam generator system capability.

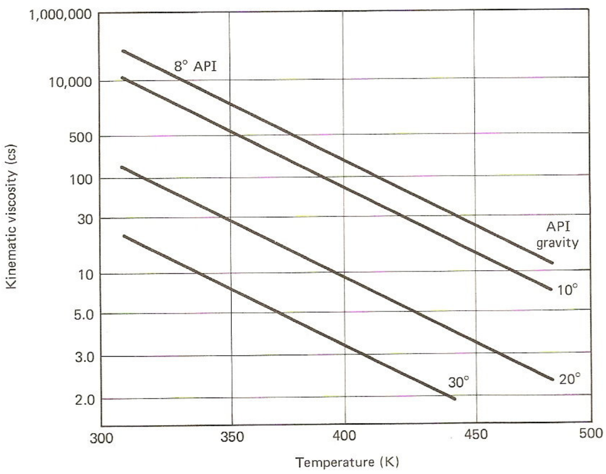


Figure 1. Temperature influence on crude oil viscosity (Lake, 1989).

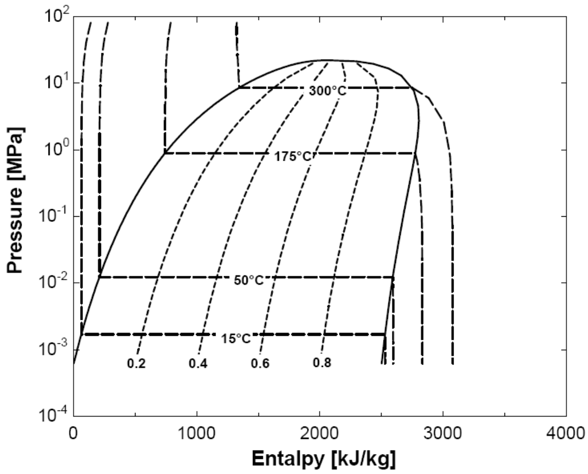


Figure 2. Water Pressure versus Enthalpy Diagram (Lake, 1989).

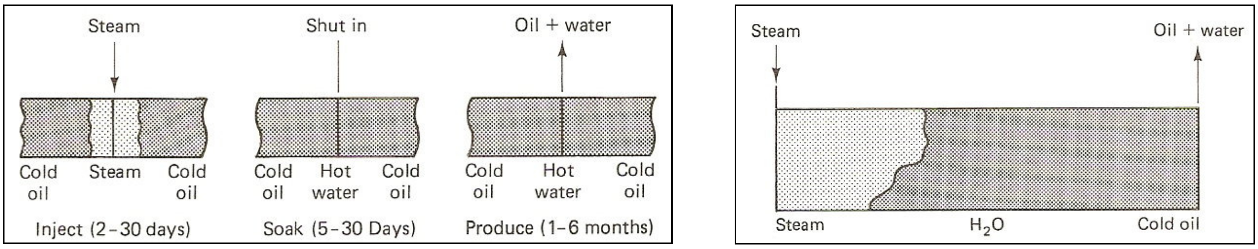
It is important to keep in mind that the thermal energy provided by steam is limited by injection conditions (pressure and temperature) and losses. Then, a technical/economical evaluation of the method effectiveness to a particular situation is mandatory. Ineffectiveness of thermal heating for too heavy oil and other recovery possibilities for light one are usually pointed throughout a range of analyses, such as reservoir screening processes and selection of operational conditions.

2.2. Steam Injection Methods and Variations

Basically steam injection processes can be applied for stimulation, usually called as cyclic steam injection, or for flooding, usually called as steam drive. While cyclic process is referred as a single well operation, steam drive uses a pattern flood with injector and producer wells (see Fig. 3(a) and Fig. 3(b)).

Cyclic steam injection is focused on oil viscosity reduction and cleaning effects around the wellbore. The process consists of a combination of injection, soak and production periods in order to heat the well vicinity and improve oil production by natural drive forces. Dimensioning of cyclic conditions depends on the reservoir characteristics, flow rates and financial return.

In steam drive, wet steam is injected continuously into a number of injection wells. A continuum steam zone is formed around the injectors and expands toward producers. Temperature inside this steam zone is approximately the same of the injected fluid. In front of the steam plume, condensate water is formed and a temperature gradient between steam temperature and original reservoir one can be observed.



(a) Stimulation (b) Flooding

Figure 3. Steam Injection Processes (Lake, 1989).

The choice of which process should be applied is frequently governed by the properties of the reservoir. In reservoirs that are small or that have relatively poor continuity, it may be prohibitively costly to drill additional wells to ensure adequate communication over close spacing and there may be no choice but to consider a stimulation treatment to increase recovery factor. Cyclic steam injection is usually preferred for economic reasons. Since it is a stimulation treatment, it accelerates oil production and there is no long delay in obtaining a production response as is the case for the steam drives. Furthermore, a single portable steam generator can be moved from well to well to apply the process to several wells at a reasonable capital cost. A drawback, however, is that final recovery may be low relative to the total oil in place in the reservoir. On the other hand, ultimate recoveries from steam drives are generally much larger. Thus cyclic steam injection followed by a steam drive is an attractive combination in that oil production is accelerated quickly and the ultimate recovery is high (Prats, 1982).

Heat amount received and retained by the productive zone determines the steam injection success. Losses can occur throughout the injection lines, wellbores and from the reservoir to adjacent zones. For the same formation volume, thin reservoirs have more surface area to lose heat when compared to thick ones. Thus, heating thin zones can be ineffective.

Another relevant parameter is injection temperature, the higher is its value, the higher is injection pressure and the lower is the heat capacity to a specified steam quality. Consequently, losses are higher and delivered energy is lower. Thus, in addition to minimize heat losses throughout the wellbore, reservoir depth limitation is also imposed to reduce injection pressure and temperature and to optimize steam latent heat transfer.

Injection pressure is also associated to steam flow rate by formation permeability. Poor permeable zones demand high injection pressure and consequently high temperature, reinforcing the heat losses effects and energy transportation inefficiency. Therefore, just high permeable formations are indicated to steam recovery application (Rosa *et al.*, 2006).

A key parameter to evaluate the performance of a steam injection project is the oil-steam ratio (OSR), defined as the volume (m^3 or bbl) of oil produced per unit volume of water injected as wet steam. In California steam drives, the OSR is about 0.25, whereas in cyclic operations, it is 0.5-1.0 in California, 0.3-0.5 in Alberta, and 3.0 in Venezuela. The latter is attributed to the unusual phenomenon of subsidence, providing a powerful compaction drive (Farouq Ali, 2002). Also, according to Gates (2007), in the field, OSR typically is between 0.1 and 0.5.

2.3. Thermal Simulator

The complexity of a thermal process reflects on the difficulties that a thermal simulator must face to implement the numerical models. The fluid properties, which are dependent on composition, pressure and temperature, vary continuously during the process. Phase behavior is calculated for a range of temperatures and heat losses to overburden and underburden must be considered. The primary effects that must be modeled in a simulator are the temperature increase and the resultant reduction in the oil viscosity. If distillation of lighter components is relevant, multicomponent representation of the reservoir oil will be needed.

From the modeling standpoint, the great difficulty with thermal processes is computational stability. The mass and energy balance equations are strongly nonlinear and closely coupled. They model complex physical processes. For instance, as steam moves through the reservoir, it condenses, greatly changing in volume. This volume change affects the energy balance, which determines how much steam condenses. In other words, movement of fluids strongly affects the movement of energy and vice versa. This close coupling of energy and fluid movement means that the equations that represent them must be solved simultaneously (Mattax, 1990). Consequently, high computational efforts and refinements are required.

3. RESERVOIR DESCRIPTION AND SCREENING EVALUATION

Focusing on main expecting results from thermal reservoir stimulation and its evaluation from a simulation process, an onshore heavy oil formation was studied. Figure 4 shows the net to gross mapping used in the simulation and Fig. 5 shows viscosity behavior against temperature. Dependence with the pressure for some properties can be seen in Fig. 6. Figure 7 shows the relative permeabilities against saturation for three temperature levels. Main reservoir parameters are presented in Tab. 1 and were also verified against screening conditions. Other rock and fluid properties are in Tab. 2.

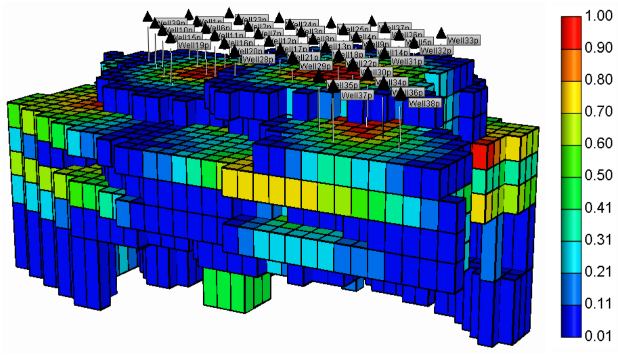


Figure 4. Net to Gross Reservoir Mapping

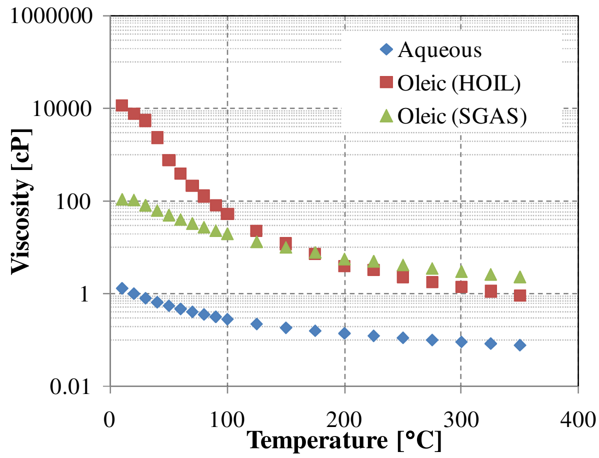


Figure 5. Liquid Viscosity versus Temperature

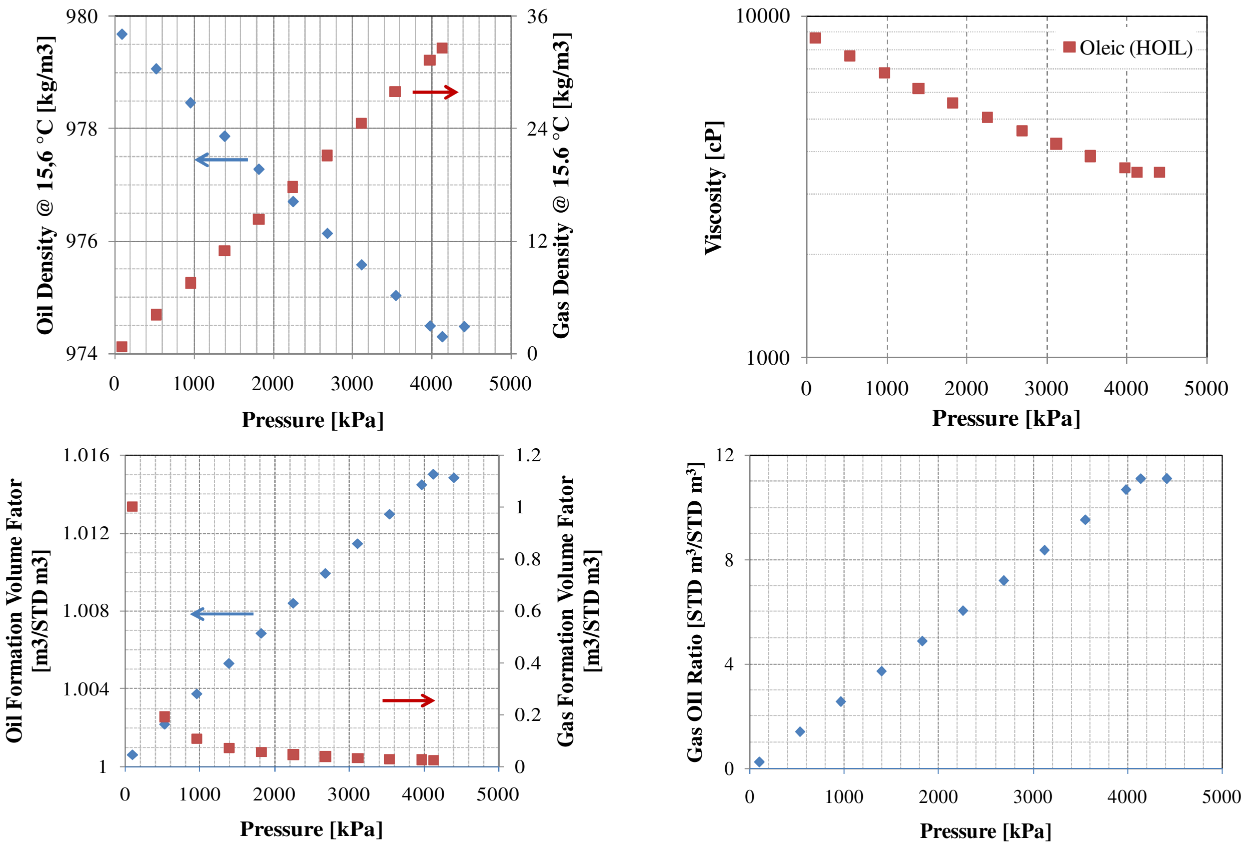


Figure 6. Properties *versus* Pressure: (a) Fluid Density; (b) Liquid Viscosity;
(c) Formation Volume Factor; (d) Gas Oil Ratio

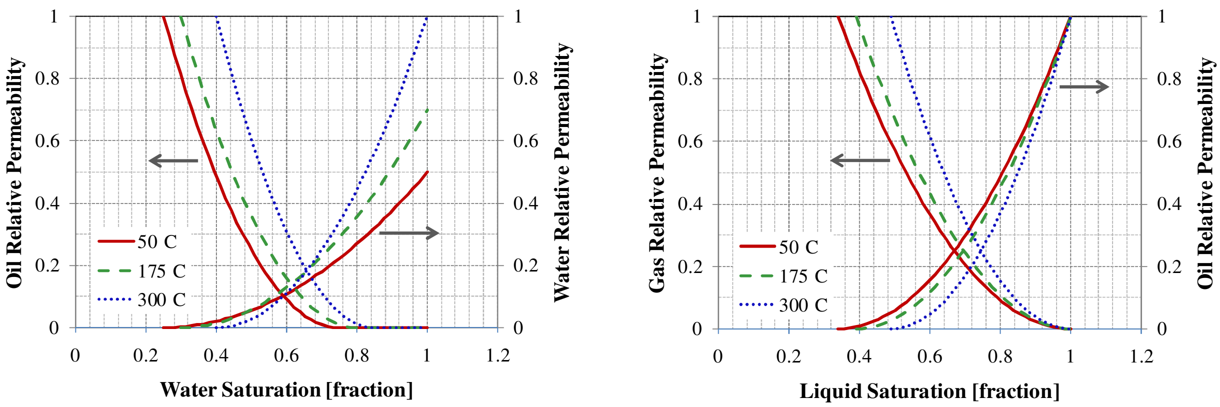


Figure 7. Relative Permeabilities (@50 C)

Table 1. Reservoir Parameters and Screening Evaluation

Parameter	Reservoir	Steam Screening*	CSS	Steam Flood
Oil Density, °API	12.8	10 - 34	< 15	13 - 25
In-situ viscosity, cp	525	≤ 15000	10,000 – 300,000	< 5,000 – 10,000
Depth, m	150 -445	≤ 910	< 910	< 910
Net-Pay, m	32	≥ 6	> 10 - 12	> 7 - 8
Porosity, fraction	0.26	≥ 0.20		
Average permeability, mD	400	≥ 250	> 500 - 1000	> 2000
Transmissibility mD-m/cp	24	≥ 1.5	0.01 – 3	3 – 100
Reservoir Pressure, MPa	3.31	≤ 10	< 10	< 17
Reservoir Temperature, °C	50	-		
Initial oil saturation, So (%)	59.3	> 40		
Initial water saturation, Swi (%)	40.7	-		
Original Oil in Place, OOIP, MM m^3 std	121	-		
Water Oil Contact, WOC, m	300	-		
Minimum initial oil, So*phi	> 0.15	≥ 0.1		

(*) adapted from Green and Willhite (1998)

Table 2. Rock and Liquid Properties

Property @ 15,6 °C	Water @101 kPa	Dead Oil @101 kPa	Live Oil @4,134 kPa
Molar Weight [kg/gmol]	0.018015	0.565	0.017025
Critical Pressure [kPa]	22106	1114.9	4624.3
Critical Temperature [°C]	374.18	497.8	-84.0
Molar Density [gmol/m3]	56550	1734.3	28188
Liquid Compressibility [1/kPa]	0	5.8E-7	5.8E-6
Thermal Expansion coefficient [1/°C]	0	7E-4	7E-4
Thermal Conductivity [J/m-day-°C]	53500	11500	0
Gas Solubility (rm^3/sm^3)	0	0	11.124
Viscosity [cp]	1.129	8,631	110
Formation Volume Factor [rm^3/sm^3]	1.0	1.0	1.015
Rock Properties @4,300 kPa			Value
Formation Compressibility [1/kPa]			2.9E-6
Formation Thermal Conductivity [J/m-day-°C]			6.6E5
Formation Volumetric Heat Capacity [J/(m3-°C)]			2.194E6
Initial Temperature of Formation Adjacent to the Reservoir [°C]			50

Adopting STARS 2008.10 from CMG (Calgary Modeling Group), a Cartesian grid containing 41x30x8 cells with $\Delta I=\Delta J=125$ m and $\Delta K(1:5)= 25$m, $\Delta K(6)= 30$ m, $\Delta K(7:8)= 70$ m dimensions was established. Simulation was conducted for 22 years, considering three scenarios: a) primary production, (b) cyclic stimulation and (c) cyclic stimulation followed by steam drive. Aiming to contribute with discussion relative to steam recovery procedures and to planning reservoir analyses difficulties, all production strategies were evaluated considering 39 unit wells, available to production/injection at the same time. Only minimum bottom-hole pressure constraint (200 kPa) was imposed to producers, while injector units were constrained by maximum pressure (7,200 kPa) or maximum flow rate (300 m^3 std/day). According to Green and Willhite (1998), it is possible to inject steam around 17,225 kPa, however the most successful projects have applied 10,335 kPa or less. This information associated with vapor heat latent capacity under specified pressure condition, justifies the selected level for injection pressure. Consequently, injected fluid temperature is 287.7 °C. Other important information is relative to steam quality, which was set as 0.75. Obtained results from simulation are presented and discussed in the next section.

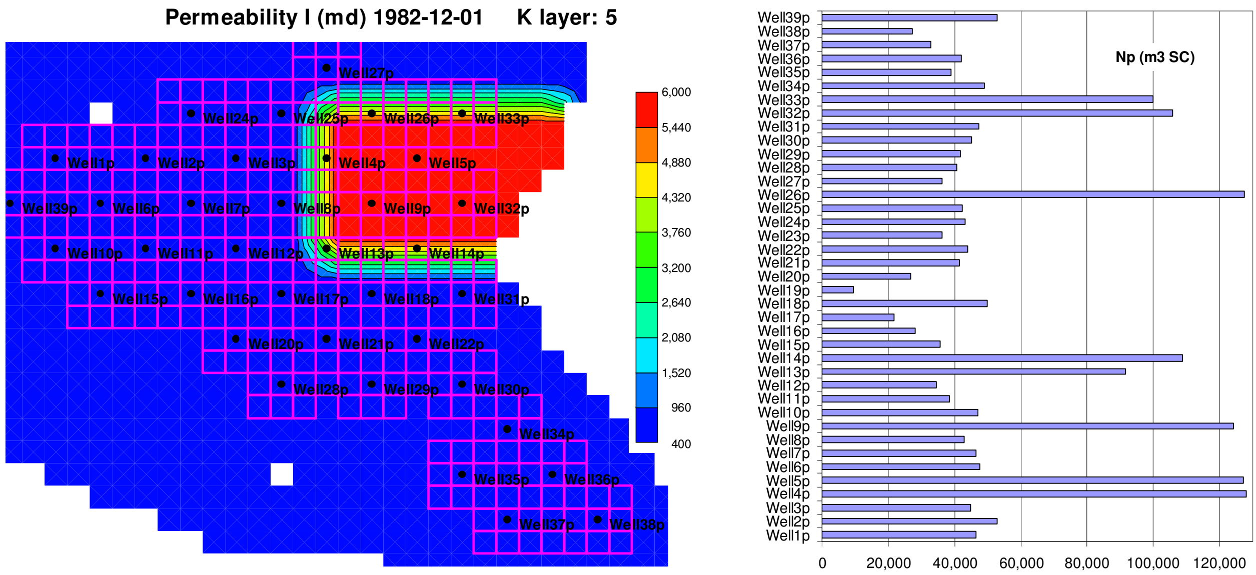
4. RESULTS AND COMPARATIVE ANALYSES

4.1. Primary Recovery

A primary recovery scenario for 22 years was implemented in order to provide a base model for the following comparative analyses with the steam improved recovery application.

Due to the low vertical permeability (~10 mD), only vertical wells were used and their location aimed an areal coverage of the field with a regular spacing, foreseeing a five-spot scheme for the steam drive phase. Drilling schedule was not considered in this analysis and all the 39 wells were supposed to have their completions and start of production at the same date of Dec-01-1982. It is useful to highlight that the number of wells is too low for a real case. For instance, the steam drive project implemented in Carmópolis Field (Brazil, SE) targeted 30 MMm³ of heavy oil with 300 wells (Mezzomo *et al.*, 2000). However, in the cases presented here, the main purpose is to discuss steam recovery mechanisms, advantages and limitations under decisions analysis standpoint, as well as under simulation and reservoir evaluation aspects. Thus, the calculation of the oil recovery factor (RF) considered the area of influence of each well to evaluate the volume of oil in place and not the entire field. This consideration was performed with the sector selection feature of the simulator, as shown by the pink grid blocks in Fig. 8 (a).

The results of this scenario show a low cumulative oil production (Np), as shown in row 1 of Tab. 3, and among the completed wells there are 8 wells with high productivity (Fig. 8 (b)), which are located in a region of high horizontal permeability (~6000 mD) in layer 5 (Fig. 8 (a)).



(a) Permeability I Map and Sector Selection for Layer 5 (b) Cumulative Oil Production per Well

Figure 8. Primary Recovery (39 producers).

4.2. Cyclic Steam Injection

To increase the cumulative oil production, the cyclic stimulation phase was initially implemented. At a first glance, one strategy to be applied could aim to save costs and do not spend resources with the 8 most productive wells, avoiding the soak period for them and stimulating only the wells of lower productivity. Another alternative could be the use of the simulator, and perform the cyclic steam injection in all the 39 wells to verify the increase on the cumulative oil production (Additional Np) for each well due to the steam stimulation. This would generate a ranking of priority and the establishment of cost savings could be based on the Additional Np and not on the simple analysis of primary production. The cycling schedule was begun at Dec-01-1982 to use natural drive forces and is described in Fig. 9. The assumption was to have a maximum of 3 wet steam generators working in parallel and 4 cycles were implemented.

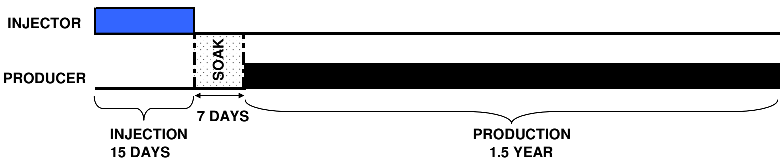


Figure 9. Cycling Periods.

The results presented in Fig. 10 show that the 8 most productive wells should not be discarded as they are among the wells with the best responses to the steam stimulation, characterized by the Additional Np parameter.

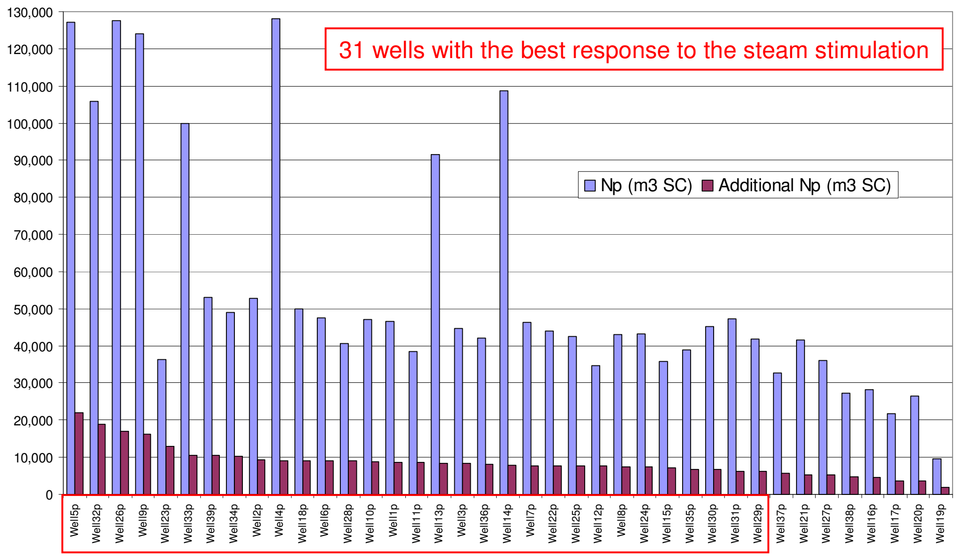


Figure 10. Ranking of Priority for Cycling based on the Additional Cumulative Oil Production.

As a final comparative result, presented in Tab. 3, the cumulative oil production (Np) and consequently the oil recovery factor (RF) for the latter analysis showed a small increase when compared to the former. Table 3 shows other parameters for each scenario, such as water-oil ratio (WOR), cumulative water injection (Wi), oil-steam ratio (OSR), process efficiency (PE) and strategy response (SR).

The PE is defined as the additional oil production per tone of injected steam in cold water equivalents. According to Queiroz (2006), the minimum value of 0.1m³/ton is usually used as reference to verify the efficiency of a steam process.

The SR is defined as the additional oil production per cumulative oil production with primary production. It shows how much of the production is anticipated due to the production strategy adopted. The main purpose of this parameter is to evaluate the efficiency of the production strategy.

The scenario of the higher additional Np also presented a small increase for PE as well as for SR.

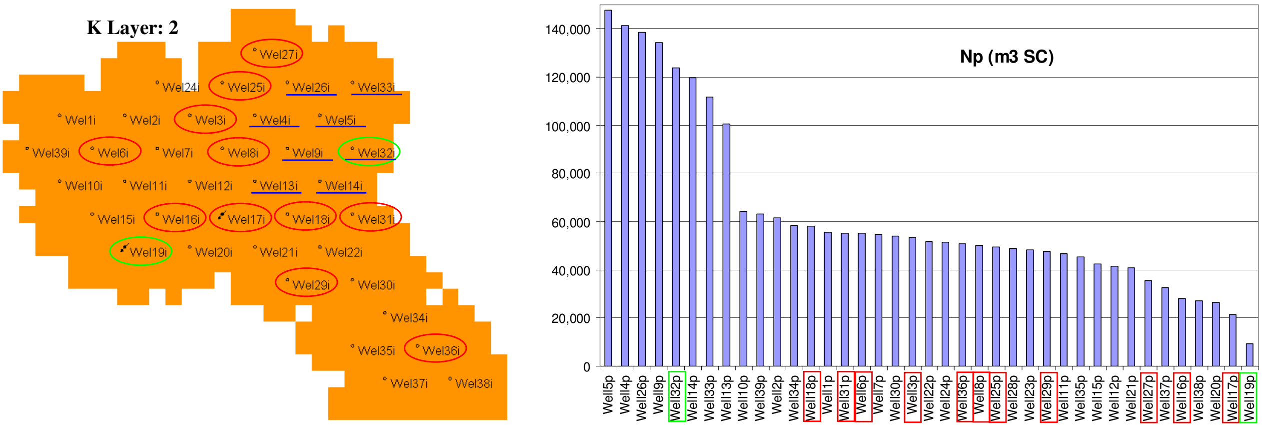
Table 3. Comparative Analysis for Cyclic Steam Injection Scenarios.

SCENARIO		DESCRIPTION	Np (m3 SC)	RF (%)	WOR (fraction)	Wi (m3 SC)	OSR[1] (fraction)	PE[2] (fraction)	SR[3] (fraction)
1 .	BASE	Primary Production 39 Vertical Wells	2,147,280	3.96%	0.85	-	-	-	-
2 .	CYCLIC INJECTION (4 CYCLES)	Cycling in 31 Wells (Lower Np) 39 Vertical Wells	2,427,680	4.48%	0.84	556,390	4.36	0.50	0.13
3 .	CYCLIC INJECTION (4 CYCLES)	Cycling in 31 Wells (Higher Additional Np) 39 Vertical Wells	2,445,420	4.51%	0.89	580,483	4.21	0.51	0.14

(1) OSR = Np/Wi; (2) PE = (NpStrategy - NpBase)/Wi; (3) SR = (NpStrategy - NpBase)/NpBase

4.3. Cyclic Steam Injection Followed by Steam Drive

To implement the following phase of steam drive, it was initially evaluated an injection scheme utilizing the same completed wells. It was verified the cumulative oil production per well after the cycling and the 12 least productive wells with a strategic location in the field were chosen to be the steam injectors. This was a tough task, since the good location for injection is also associated with high productivity. Thus, two alternatives were implemented: the first was to choose all the injectors out of high productivity region and the second was to choose one of the injectors within the high productivity region. Figure 11 (a) shows the location of the wells: the blue underlined wells are within the high productivity region and the circled wells show the chosen injectors, considering that well 19 (outside the high productivity region) and well 32 (within the high productivity region) are green circled to highlight that they are not chosen simultaneously, well 19 is chosen in addition to the red circled wells for the first alternative and well 32 is chosen for the second alternative. Figure 11 (b) shows the selection of the injectors using the Np parameter as criteria of decision, and the chosen injectors are circled with the same colors definition adopted in Fig. 11 (a). The steam drive was begun at Mar-01-88.



(a) Well Location Criteria for Steam Drive

(b) Cumulative Oil Production Criteria for Steam Drive

Figure 11. Methodology to Choose the Injector Wells for Steam Drive Phase.

The results, as shown in Tab. 4, reflect the tradeoff of the steam drive scenarios in relation to the cyclic steam stimulation scenarios: the RF increases while the OSR decreases, which is perfectly acceptable since the economic viability is still maintained.

The comparative analysis between the two steam drive scenarios shows that it was worth to loose one producer of high production in order to provide a better thermal communication toward some of the high producers. Their production increase compensated the lost of one high producer to injection, and this latter scenario presented a higher RF. Furthermore, this last scenario presented a higher efficiency of the production strategy with an anticipation of 174% of the cumulative oil production when compared with the primary recovery, keeping economic values for OSR and PE.

Table 4. Comparative Analysis for Seam Drive Scenarios.

SCENARIO		DESCRIPTION	Np (m3 SC)	RF (%)	WOR (fraction)	Wi (m3 SC)	OSR¹ (fraction)	PE² (fraction)	SR³ (fraction)
4 .	CYCLIC INJECTION (4 CYCLES) + STEAM DRIVE	Cycling in 31 Wells (Higher Additional Np) 39 Vertical Wells 12 Injectors / 27 Producers All Injectors out of the High Productivity Region	5,496,800	10.14%	2.40	17,799,400	0.31	0.19	1.56
5 .	CYCLIC INJECTION (4 CYCLES) + STEAM DRIVE	Cycling in 31 Wells (Higher Additional Np) 39 Vertical Wells 12 Injectors / 27 Producers 1 Injector within the High Productivity Region	5,876,680	10.84%	2.49	19,284,500	0.30	0.19	1.74

(1) OSR = Np/Wi; (2) PE = (NpStrategy - NpBase)/Wi; (3) SR = (NpStrategy - NpBase)/NpBase

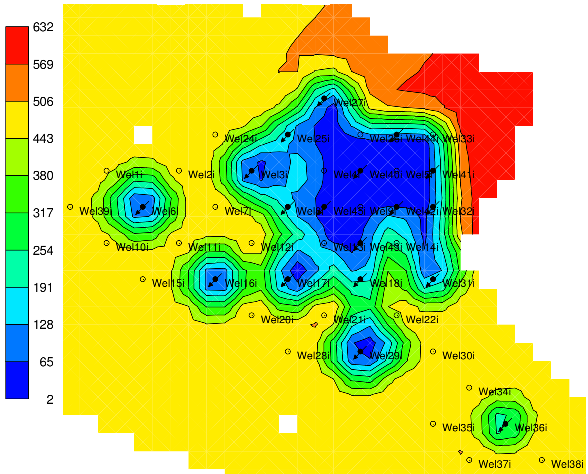
Also, a third alternative injection scheme was evaluated with new wells specially completed for steam injection. This new scheme involved 6 new injectors completed within the region of high productivity in addition to the 12 wells chosen in the latter alternative.

Since steam drives involve moving hot fluid (wet steam) from one well to another, they require an appropriate well spacing to the flow conditions of the reservoir. Thus, the smaller spacing between injector and producer of this scenario improved even further the thermal communication (Figures 12(a) and (b)), resulting in a higher RF and in an anticipation of 234% of the cumulative oil production, still with economic values for OSR and PE, as shown in Tab. 5.

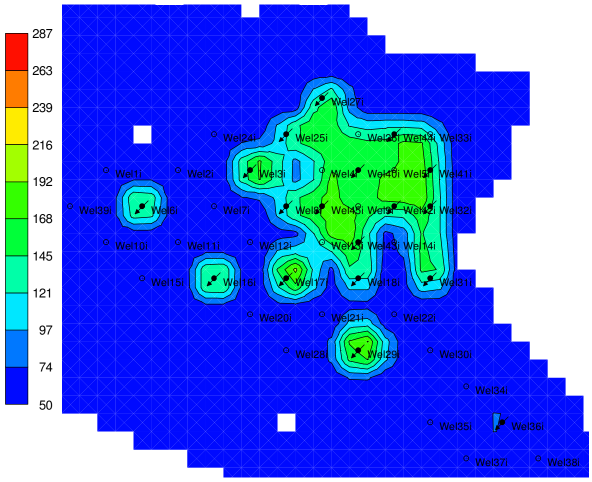
Table 5. Results of the Seam Drive Scenario with New Injection Wells.

	SCENARIO	DESCRIPTION	Np (m3 SC)	RF (%)	WOR (fraction)	Wi (m3 SC)	OSR¹ (fraction)	PE² (fraction)	SR³ (fraction)
6.	CYCLIC INJECTION (4 CYCLES) + STEAM DRIVE	Cycling in 31 Wells (Higher Additional Np) 45 Vertical Wells 18 Injectors / 27 Producers 7 Injectors within the High Productivity Region	7.170.610	13,23%	3,63	30.863.200	0,23	0,16	2,34

(1) OSR = Np/Wi; (2) PE = (NpStrategy - NpBase)/Wi; (3) SR = (NpStrategy - NpBase)/NpBase



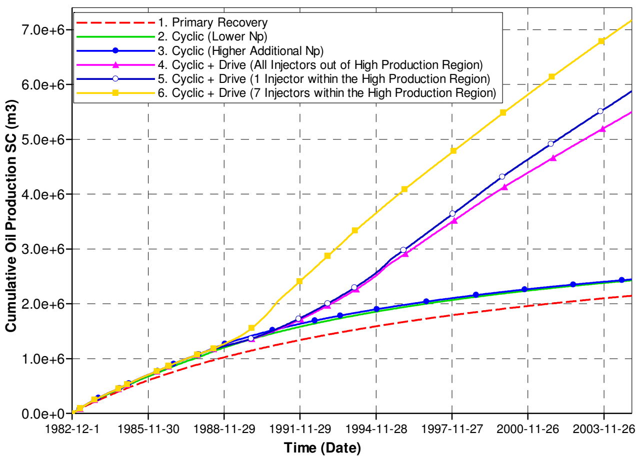
(a) Oil Viscosity (cp)



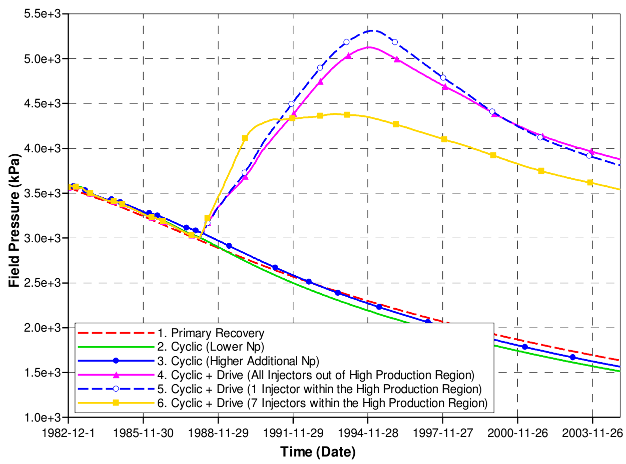
(b) Temperature (ºC)

Figure 12. Steam Drive Phase With New Injection Wells.

An overview of the cumulative oil production vs. time and average field pressure vs. time for all the scenarios are shown in Figures 13 (a) and (b) respectively. It is interesting to point out that the cyclic process, which occurs from Dec-1982 to Feb-1988, uses the same natural drive force as the primary recovery and the viscosity reduction due to thermal stimulation is the factor to the oil production increase. Also, it is possible to observe that the cyclic steam process offers an immediate but small increase of the oil recovery, while the steam drive, which was begun at Mar-1988, requires a period to establish the thermal communication between injector and producer in order to greatly increase the oil recovery. And the better this thermal communication is established, the higher is the ultimate cumulative oil production.



(a) Cumulative Oil Production for All Scenarios



(b) Field Pressure Response for All Scenarios

Fig. 13. Overview of the Analyzed Scenarios.

5. CONCLUSION

The check screening procedure offers a first guideline to validate the chosen thermal recovery method. It is approximate only, since the development of a petroleum field involves many parameters and it is a complex processes, especially when applying thermal methods. Thus, the thermal numerical simulator is a fundamental tool to help on the prediction of reservoir behavior before a production strategy is chosen.

The analyzed scenarios showed interesting insights regarding steam recovery mechanisms. For the scenarios of cyclic stimulation it was observed that if there are limiting conditions the most productive wells should not be discarded, since flow conditions are favorable and the good response to stimulation compensates the shutting period. The cyclic steam stimulation should be applied since the beginning of the heavy-field development to utilize more efficiently the reservoir natural drive forces. Regarding the scenarios with steam drive phase, heat continuity is fundamental for the efficiency of the drive process. Since it involves moving hot fluid from one well to another, the better response is obtained with a higher covering drainage area which promotes a better heat continuity. Thus, reduced well spacing must be considered if the reservoir presents good continuity for the flow of fluids. The results of the last drive scenario with additional injection wells reflected this analysis since the reduced well spacing promoted a better thermal communication and consequently resulted on a great increase on the ultimate cumulative oil production, maintaining economic values of SOR and PE as described in item 2 of this paper. Finally, based on the overview graphics of Np (Fig. 13(a)) and average field pressure (Fig. 13(b)), it was possible to confirm that the cyclic steam process offers an immediate but small increase of the oil recovery, while the steam drive requires a period of thermal communication establishment between injector and producer in order to greatly increase the ultimate oil recovery.

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