EVALUATION OF RESERVOIR PARAMETERS IN ENHANCED OIL RECOVERY PROJECTS WITH GAS INJECTION

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ABSTRACT

In the oil industry, maximizing the production of hydrocarbons found in the reservoir is of great importance. Oil recovery factors depend not only on rock properties and fluid conditions, but also on the technology available to extract the highest percentage of crude oil. One of the most common techniques is enhanced oil recovery with gas injection, which adds energy to a reservoir in order to stimulate production, increase the recovery factor and extend the life of the reservoir.

Therefore, the objective of this research is to evaluate the reservoir parameters and production behavior of the reservoir through enhanced oil recovery with gas injection. The methodology was based on the analysis of well data, production history, reservoir pressure, then the PVT information existing in the area was validated, the geological model provided was integrated, the STOIIP of the reservoir was calculated, then the reserves were determined through the analysis of production decline curves and material balance, finally, an exploitation plan was generated to drain the remaining reserves of the reservoir through enhanced oil recovery with gas injection.

Finally, the results indicate that the initial behavior of the reservoir was undersaturated, with a calculated STOIIP of 85.7 MSTB and associated remaining reserves of 8.8 MSTB; consequently, an exploitation plan was proposed in which 7 new wells are integrated to drain the reservoir reserves, ratifying this project was optimum with gas injection during 15 years.

INTRODUCTION

During primary oil production, the natural reservoir pressure declines, so it is necessary to resort to enhanced oil recovery. These are applied in order to increase the energy of the reservoir, and thus recover as much of the fluid from the reservoir as possible.

There are many factors that influence the amount of additional oil by enhanced schemes, especially by gas injection, which is a conventional method widely used to obtain extra oil recovery, due to the profitability when applying them. For Ferrer (2001) the most important factors are: reservoir fluid properties, drive mechanism, reservoir geometry, sand continuity, structural framework, rock properties, temperature and reservoir pressure.

For this reason, this project was developed under a geological information based on 3D seismic, where it was possible to integrate the reservoir data obtaining consistent results of the dynamic behavior over time, which will help to characterize the reservoir fluid, calculate the volumes of existing hydrocarbons, determine the recoverable and remaining reserves; in turn, recommend enhanced oil recovery with gas injection which generates benefits of how to improve the production-reserve ratio, estimate the recovery factor, increase productivity per well and extend the reservoir life.

ANALYSIS OF THE MAIN RESERVOIR CHARACTERISTICS

The reservoir under study is characterized by a 5º north-dipping, east-west truncated monocline structure truncated by a northeast-southwest trending, 45º southeast dipping normal fault system, with fault displacement varying between 190 and 360 ft along the fault.

Figure 1 shows the isopach-structural map of the reservoir under study.

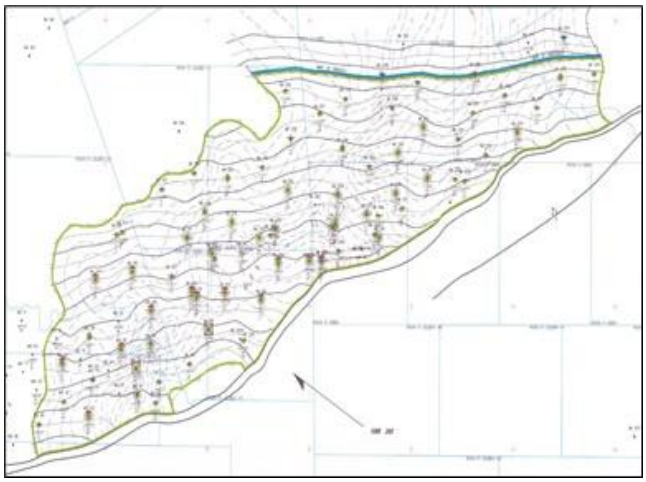

Figure 1. Reservoir Isopach-Structural Map.

According to the geological interpretation of the reservoir under study, it was determined that it corresponds to a stratigraphic - structural trap.

On the other hand, Table 1 shows the official data of the reservoir, these values allow us to have an estimate of the properties of the study area, in addition to having a vision of the type of fluid to be characterized, which represent a basis for the study.

Table 1. Reservoir Official Data. ´

DATA	Range
Discovery	01/1962
Porosity (%)	14,9
Absolute Permeability (mD)	118
Initial Water Saturation (%)	22
Reservoir Area (acres)	6.241
Average Thickness (feet)	20
Net Pay Volume (acres-feet)	127.000
Oil Density (°API)	22,9
Original Pressure (psia)	4.850
Saturation Pressure (psia)	3.133
Initial Gas to Oil Ratio (SCF/STB)	604
Oil Volumetric Factor (RB/STB)	1,30
Stock Tank Oil in Place (MSTB)	88
Primary Reserves (MSTB)	14
Reservas Secundarias (MSTB)	12
Total Reserves (MSTB)	26
Total Recovery Factor (%)	30
Cummulative Oil Production (MSTB)	15,1
Oil Remaining Reserves (MSTB)	10,9
Original Gas in Place (TCF)	0.053
Cummulative Injected Gas (MMSCF)	46

(M=Million , MM=Billion)

In addition, the reservoir has an area of 6700 ft, with a volume of 130,000 acre-feet and a OWC at 11660 ft.

PROPOSED METHODOLOGY FOR THE RESERVOIR ANALYSIS

Static Model

For the evaluation of the project, the first step was to integrate the geological model of the reservoir, updating the geological characteristics in order to define the contours or limits of the reservoir, continuity of the sand, verify the structure and location of the water-oil contact.

Subsequently, a review of the petrophysical parameters was made by means of Landmark's Petroworks tool. Density-Neutron, Gamma-Ray, SP, Microlog logs were available. The methods used for the calculations of the petrophysical properties of the reservoir were the following:

Gamma Ray Method for the calculation of the shale volume (Vsh) using equation 1. Where GR and GRmin. correspond to the value read in the log and to the minimum value of the gamma ray profile.

Ecuation 1

$$V_{sh} = \frac{GR - GR_{min}}{GR_{max} - GR_{min}}$$

SP Method for the water resistivity calculation with the ecuation 2. where SSP represents the spontaneous potential, T_fm is the formation temperature, R_mfe is the equivalent resistivity of the mud filtrate and R_we is the equivalent resistivity of the formation.

Ecuation 2

$$SSP = -\left(61 + 0.133 * T_{fm}\right) * \log\left(\frac{R_{mfe}}{R_{we}}\right)$$

Density-Neutron Method, for the porosity calculation with the ecuation 3. where ρ_ma is the matrix density, ρ_b is the formation density and ρ_f is the fluid density.

Ecuation 3

$$\emptyset = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_f)}$$

Timur Model to determine the permeability from connate water saturation and porosity, using equation 4

Ecuation 4

$$K = \frac{(93\emptyset^{2.2})}{S_{wi}}$$

Modified Simandoux Model for calculating water saturation using equation 5 (Bassiouni, 1994). Where Rw, Rt, Rsh represent connate water resistivity, deep resistivity reading and shale resistivity

Ecuation 5

$$S_w = 0.405\frac{R_w}{\emptyset^2}\sqrt{\frac{5\emptyset^2}{R_w R_t} + \frac{V_{sh}}{R_{sh}^2} - \frac{V_{sh}}{R_{sh}}}$$

Once the petrophysical properties of the reservoir wells were obtained, a thickness-weighted average was calculated to determine an average value of the properties of the study area, which are useful to calculate the original oil in place in the reservoir. The equations used to obtain the values of each of the properties are shown in equations 6, 7, 8 and 9.

Ecuation 6. Calculation of the average volume of shale for the reservoir.

$$Vsh = \frac{\sum_{i=1}^{i=n} Vsh_i * AN_i}{\sum_{i=1}^{i=n} AN_i}$$

Ecuation 7. Calculation of average porosity in the reservoir.

$$\phi = \frac{\sum_{i=1}^{i=n} \phi_i * AN_i}{\sum_{i=1}^{i=n} AN_i}$$

Ecuation 8. Calculation of average initial water saturation in the reservoir.

$$Swi = \frac{\sum_{i=1}^{i=n} Sw_i * AN_i}{\sum_{i=1}^{i=n} AN_i}$$

Ecuation 9. Calculation of the average permeability of the reservoir.

$$K = \frac{\sum_{i=1}^{i=n} K_i * AN_i}{\sum_{i=1}^{i=n} AN_i}$$

Hereinafter, isoproperty maps were made using the OFM application, in order to observe the distribution of petrophysical properties and choose the best zones with flow capacity, generating a map that involves both permeability and porosity, resulting in the best properties are in the central and northern part of the reservoir, in these maps the advances of the fronts were plotted to delimit the study area, as shown in Figure 2.

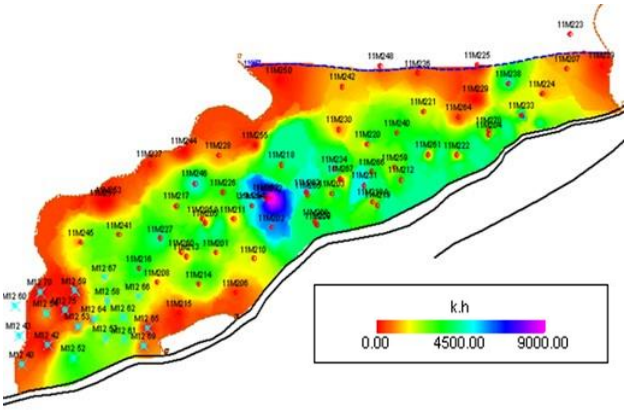

Figure 2. Isoproperties Maps (Permeability-Thickness)

Dynamic Model

The behavior of the fluids in the porous medium, their distribution and the way they move in it are analyzed. Due to the absence of core in the reservoir, the relative permeability curves were calculated through the SPIYAC tool, both for the gas-oil and water-oil system; using the TOTAL correlations which fits the study area.

In order to generate the curves, values obtained from the petrophysical evaluation (initial water saturation and average permeability of the reservoir) and a pore size distribution index value of 1.668 were introduced; which value was the result of a capillary pressure analysis created by TOTAL as shown in Figure 3.

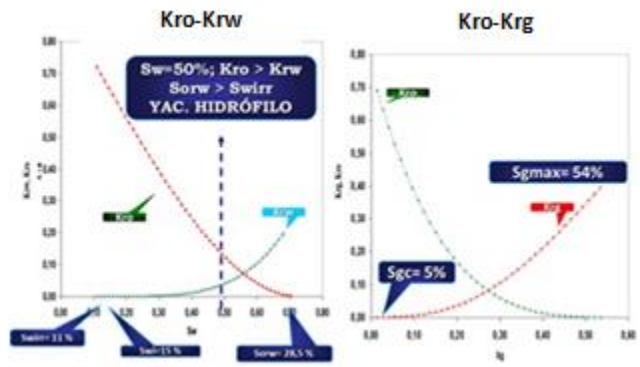

Figure 3. Relative Permeability Curves

Then, the production analysis is performed, generating graphs of oil, gas and water accumulated behavior, oil, gas and water rate, %W&S, GOR, all as a function of time; these graphs were made through the OFM application as shown in Figure 4.

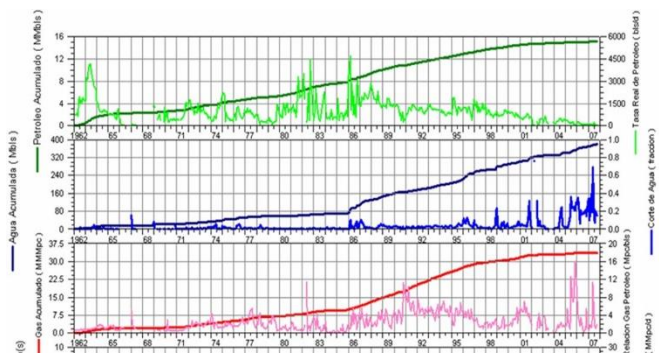

Figure 4. Reservoir Production History.

In order to know the origin of produced water and the main causes of undesirable water volumes, the so called CHAN diagnostic curves were made, which have a behavior that shows how the studied fluid should be if it moves by normal displacement, channeling, coning or mechanical communication. After analyzing the water production, the new accumulated volume of reservoir water is presented (Figure 5).

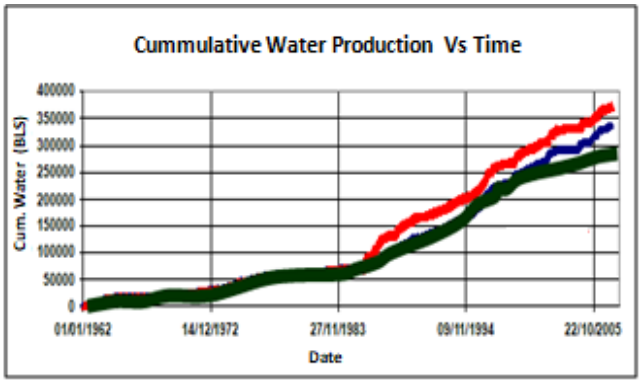

Figure 5. Adjusted Cumulative Water

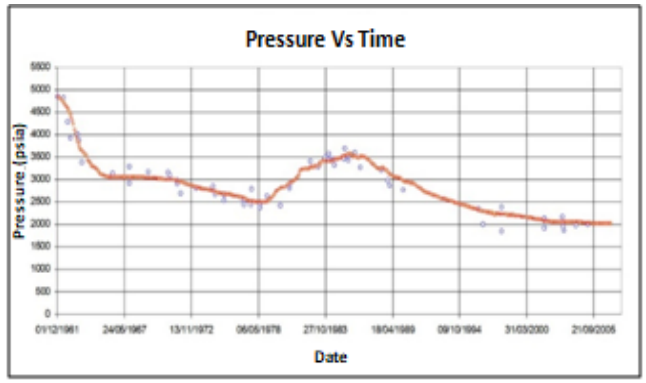

Figure 6. Pressure Behaviour of the Reservoir S1 11M-201.

Subsequently, the analysis of the pressure behavior was carried out and these are extracted by means of the BHP found in the well records. All these pressures have to be extrapolated to the same level; for this reason, it is necessary to calculate a reference level called Datum by means of equation 10,11.

Ecuation 10. Calculation of pressures at the midpoint of the sand face.

$$P_{arena} = P_{med} + G_{pozo} * (h_{arena} - h_{med}.)$$

Ecuation 11. Calculation of Reservoir Pressure Gradiente

$$Gy = 0.433 * \rho o$$

Ecuation 12. Calculation of pressures at Datum reference level.

$$P_{Datum} = P_{yac} = P_{arena} + G_{yac} * (\Pr of \operatorname{Re} f + EMR - h_{arena})$$

Once the pressures are obtained, a graph of these values as a function of time is constructed, this is done in order to obtain the trend of the historical pressure throughout the productive life of the reservoir, and thus be able to discard the points that are out of the same, as shown in Figure 6.

The consistency of the PVT test was then verified based on a module of the SPIYAC tool using the Standing formulation developed by the French oil company TOTAL.

Immediately, the Original Oil in Place (STOIIP) is calculated by the volumetric method, the structural isopach map was used to determine the gross volume by means of the SIGEMAP tool. The initial volumetric factor and initial oil solubility were obtained from the previously validated PVT. Porosity and water saturation were calculated through the weighted petrophysical parameters. With all these values, the Original Oil in Place is obtained from equation 13 and the GOIIP from equation 14.

Ecuation 13. Original Oil in Place Calculation (STB)

$$STOIIP = 7758 * \frac{Vb * \varphi * (1 - Swc)}{Boi}$$

Ecuation 14. Original Gas in Place Calculation, (SCF)

$$GOIIP = STOIIP * GOR_i$$

The Oil in Place is then calculated by material balance using the MBAL program, entering pressure behaviour, production history, PVT and petrophysical data. In addition, with this program it is possible to know the predominant production mechanisms, reserves and recovery factor of the reservoir.

Finally, an exploitation plan was generated according to the current conditions of the reservoir, for which it was necessary to integrate the information of the static and dynamic model of the reservoir; in order to study the areas with greater opportunities and to be able to drain these reserves through enhanced oil recovery with gas injection and drilling new wells or with existing drainage points in the reservoir.

RESULTS / DEVELOPMENT

Reservoir Characterization

Analyzing the natural depletion stage provided a series of important data such as corroborating the initial reservoir pressure of 4850 psia, when plotting the GOR it was observed that at the beginning of its productive life it was undersaturated, then it had a progressive increase of the GOR showing that the pressure has fallen below the saturation pressure, as can be seen in Figure 7; Likewise, this phenomenon, since there is a double slope in the pressure decline and the intercept of these is indicative of the bubble pressure value, which is in a range between 3000 psia and 3300 psia.

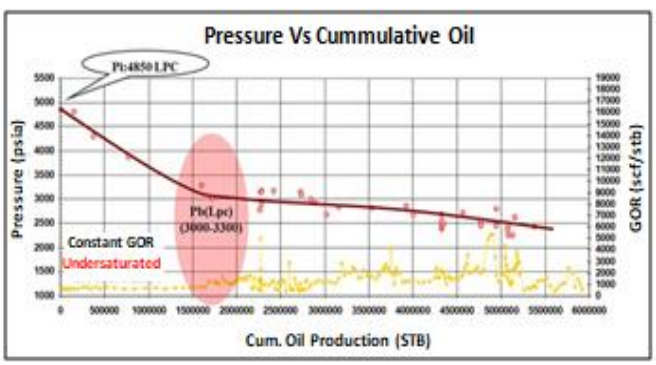

Figure 7. Pressure Behaviour vs GOR.

Oil in Place Calculation - Natural Depletion

For the calculation of the POES by the volumetric method, previously calculated data were taken as for example the structural isopach map integrated previously where through the calculation the gross volume of the reservoir with a value of 130000 acres*ft, the initial volumetric factor and the initial solubility of gas in oil were obtained from the previously validated PVT. Porosity and water saturation were calculated by petrophysical evaluation as shown in Table 2.

Table 2. Calculated and Validated Data.

DATA	Results
Porosity (%)	13,7
Absolute Permeability (mD)	118
Initial Water Saturation (%)	15
Initial Oil Saturation (%)	85
Reservoir Area (acres)	6.700
Average Thickness (feet)	19
Net Pay Volumen (acres-feet)	130,000
Oil Density (°API)	22,9
Original Pressure (psia)	4.850
Saturation Pressure (psia)	3.133
Initial Gas to Oil Ratio (SCF/STB)	604
Initial Oil Volumetric Factor (RB/STB)	1,3904

By following this methodology in this study, a STOIIP of 85.2 MSTB and a GOIIP of 0.0515 TCF; these values have a percentage difference of less than 5% with respect to the official values.

The data was loaded into the MBAL application as part of the methodology and an initialization run was performed without aquifer connection in order to verify the existence or not of additional energy in the reservoir as shown in Fig. 8.

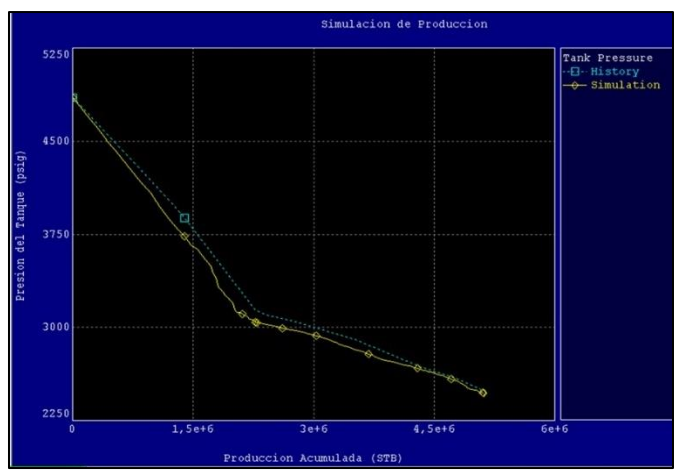

Figure 8. Initialization Run - Pressure and Production Match.

Thus, additional energy is required for the simulated pressure to match the historical reservoir pressure, therefore, it is inferred that there is an aquifer associated with it, the Campbell method graph was generated, which reflects the energy of the aquifer (Figure 9).

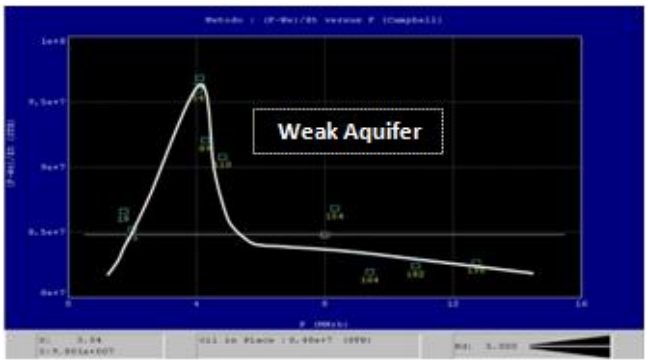

Figure 9. Campbell Method.

Similarly, the existence of an external energy source or associated aquifer is observed, where the Campbell method indicates that the reservoir is influenced by the action of a weak aquifer, which is consistent with the low accumulated water production for the entire reservoir (280 KSTB) and the little difference between the pressure curves. Once this was verified, sensitivities were carried out regarding the type of model to be used, achieving a better fit through the Smoll Plot aquifer model.

After identifying the type of aquifer and its contribution, a second run was performed to verify if it matches the simulated production and pressure with the historical reservoir as shown in Figure 10.

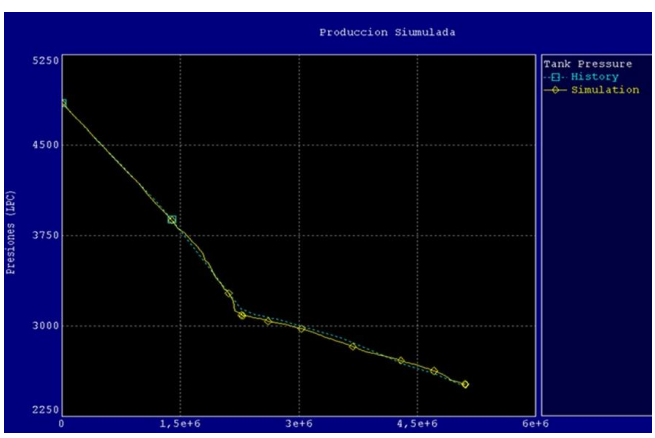

Figure 10. Pressure and Production History Match.

Subsequently, the graphic method to be used was chosen to validate the STOIIP calculated by the volumetric method, obtaining a better comparison with the F-We versus Et method. In which the linearity of the points compared for both production and pressure was verified. Figure 11 shows the F-We versus Et method, reflecting a STOIIP of 84.9 MSTB was obtained. It can be highlighted this graph as the best comparison due to the linearity of its points.

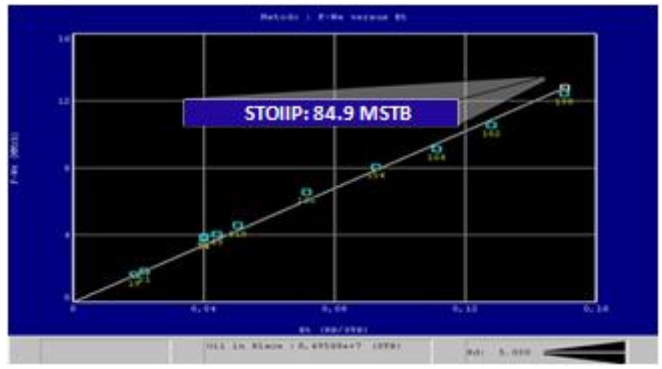

Figure 11. Graph Method for STOIIP Calculations.

Similarly, the oil in place was calculated by the analytical method and a value of 85.7 MMBN was obtained, which corroborates that calculated by the volumetric method of 85.2 MMBN with an error percentage of less than 5% (See Figure 12).

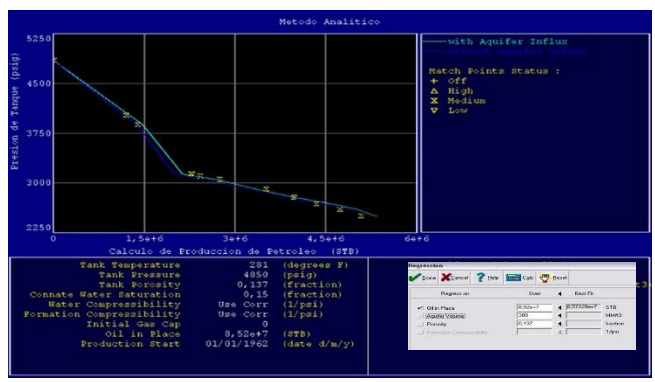

Figure 12. Analytic Model for Oil in Place Calculation.

Reservoir Oil in Place including Gas Injection as a method of Enhanced Recovery

When calculating the POES of the reservoir using the natural depletion stage, the volume of gas injected could not be compared with the pressure behavior of the reservoir in the secondary recovery stage, therefore, the production data, gas injection and

pressures of the entire productive life of the reservoir were loaded in order to verify the previously validated data and thus have greater certainty of the volumes produced and injected into the reservoir. This must be done in all the complete evaluation methodology of a Gas Injection project, therefore a run was performed to verify if the simulated data matched the historical data.

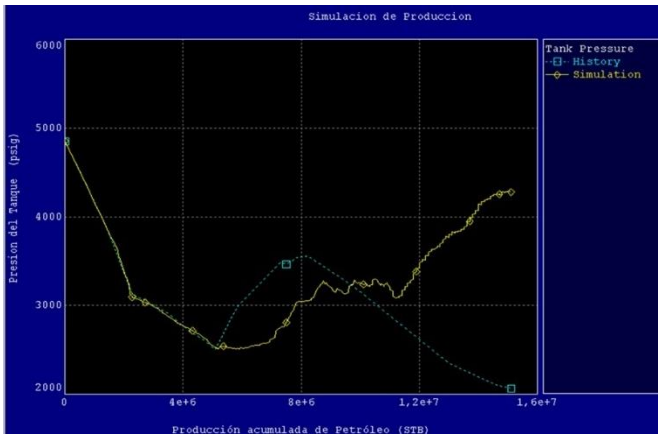

Figure 13. Pressure and Production History Match.

The historical data and simulated data did not match, since the trend line does not match, having a great difference, the pressure reported by the simulator for the year 2007 is approximately 4300 psia; while the historical pressure for that year reported in the study is approximately 2060 psia, these pressure values were reviewed, analyzed and validated rigorously, therefore it can be said that the injected volume does not match the behavior of the reservoir pressures, it is for this reason that the volume of gas injected into the reservoir will be reviewed and runs were made in the simulator to verify the amount of injection necessary to match the pressure and injection data.

Effect of Gas Injection and Reservoir Replacement Factor Calculations

In order to evaluate the amount of gas injected in a project, the volume of gas injected in the reported reservoir must be plotted and validated, in this case it is approximately 46 Billion of SCF. (See Figure 14).

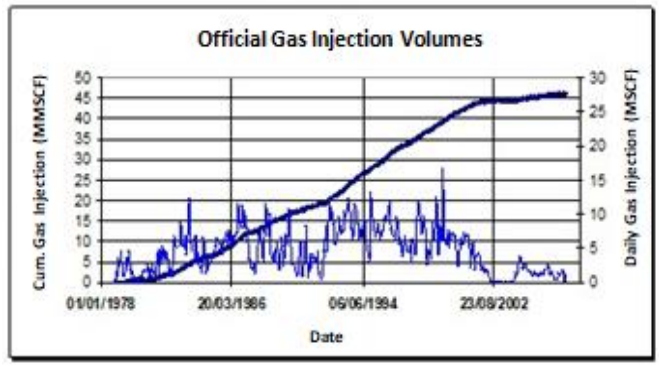

Figure 14. Official Gas Injection Volumes.

The replacement factor (Rf) was calculated with the data provided by the simulator, it was verified that the injected volumes are greater than those necessary for the comparison of the reservoir pressure behavior. (See Figure 15).

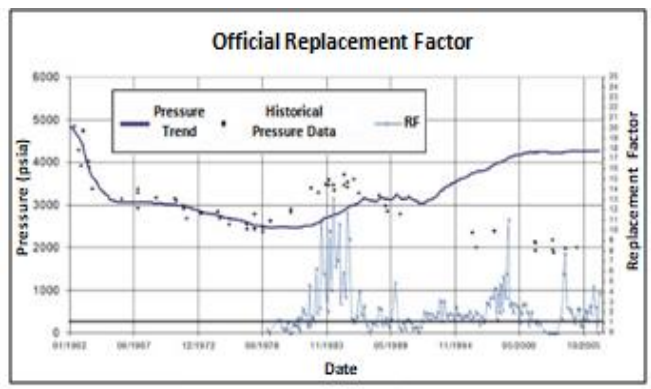

Figure 15. Official Replacement Factors Values.

It is observed in Figure 15 that the replacement factors do not match the historical pressure behavior, with values greater than 1 throughout the injection project, which is indicative that the injected volumes are greater than the volumes produced and therefore the pressure should always increase, which did not occur in the pressure maintenance stage where it decreased progressively to approximately 2060 psia, so the volume of gas injected must be corrected. (In many projects the field operators take bad measurements of the injected gas or have failures in the pressure gauges therefore the engineers must correct these values).

Different runs were performed in the simulator until the values were matched and then the injected gas volume was corrected by subtracting approximately 20% of the official gas, at the beginning of the injection the data was not officially loaded in the history so it had to be reconstructed with the values of

the injected volume that allowed to match the reservoir data in the repression stage, then gas was subtracted in the maintenance stage in which the pressure declined progressively. The corrected injected gas is 33.4 Billion of SCF. (See Figure 16).

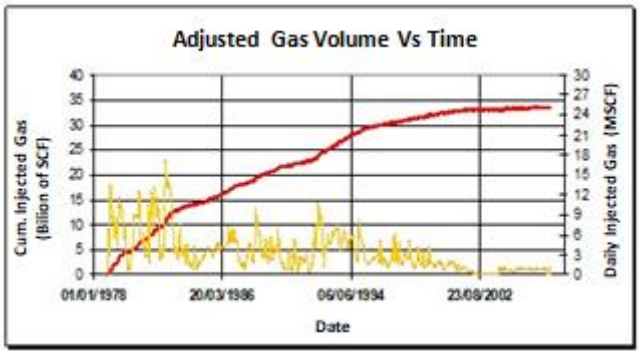

Figure 16. Re-Calculated Injected Gas Volumes.

With this corrected injected gas, the replacement factor was recalculated, which does represent the pressure behavior of the reservoir, since at the beginning the injected volume is greater than the produced and the replacement factor is greater than 1, this is because it is in the re-pressurization stage of the project where the pressure was increased from approximately 2500 lpc to about 3500 lpc, but in the second stage of the project where the aim is to maintain the pressure reached, the volumes of gas injected were lower than those produced, therefore the values of the replacement factor was less than 1, which results in a decrease in pressure. (See Figure 17).

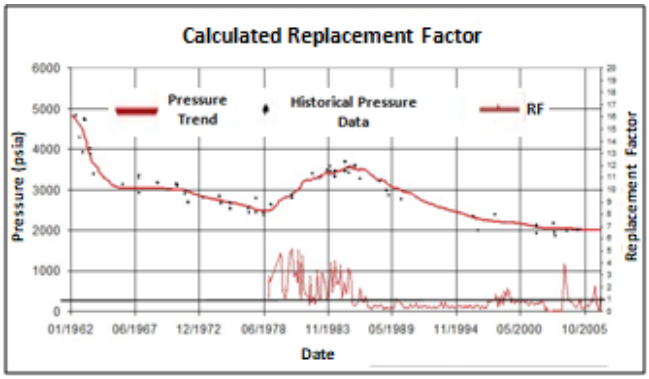

Figure 17. Calculated Replacement Factor.

After correcting the volume of gas injected and verifying the consistency of the calculated values, the F-We versus Et graphical method was used, where the values of production, gas injection and reservoir pressures were checked, with linearity between the points and ratifying the STOIIP calculated in the Natural depletion stage. (See Figure 18).

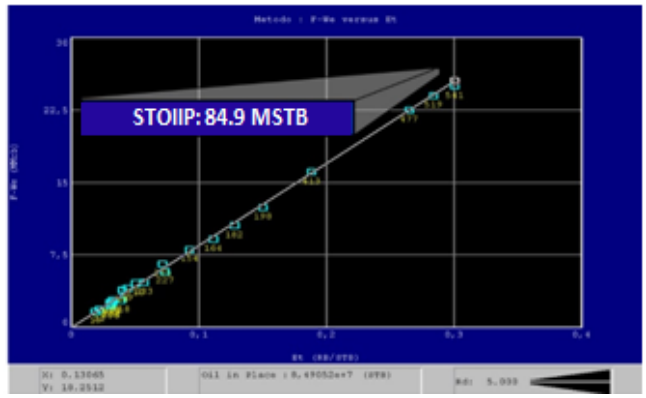

Figure 18. Graph Method for the STOIIP Calculation with Gas Injection.

Production Drive Mechanism in the Reservoir

In the production history of the reservoir, the different production mechanisms responsible for hydrocarbon recovery play an important role, through the study it was determined that the greatest influence among the mechanisms present was the expansion of the fluids with 55% and in second place with an influence of 30% the injection of gas, with less weighting we have the compressibility of the rock with 5% and the influence of the aquifer with 10%. (See Figure 19).

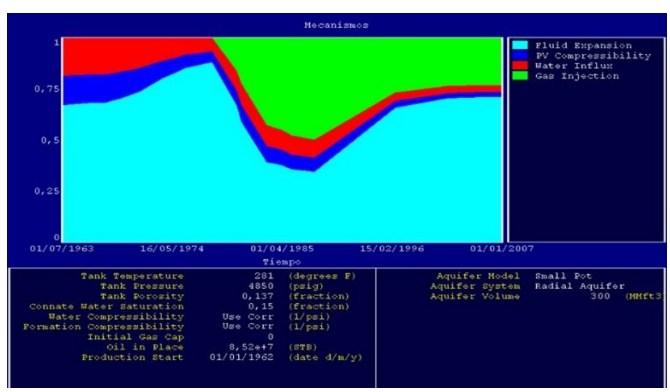

Figure 19. Reservoir Production Drive Mechanism.

Also, total recoverable reserves can be estimated with this methodology using the MBAL tool, establishing a production limit rate of 30 BN/D for each well. Where total reserves of 23.9 MMBN were obtained as shown in Figure 17, which corresponds to a recovery factor of 28.2 % and remaining reserves of 8.5 MMBN.

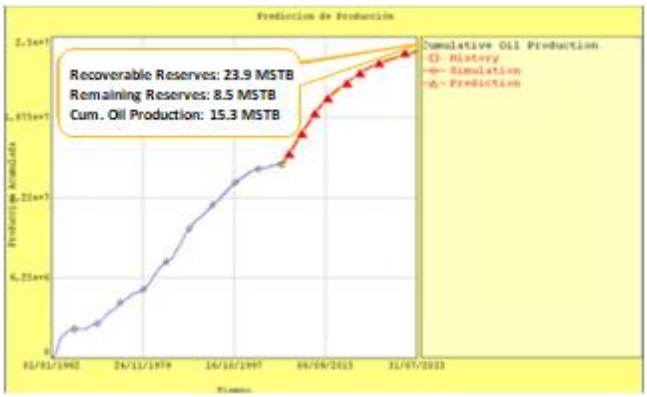

Figure 17. Total Reserves Calculation.

Evaluation of the Reservoir Exploitation Plan.

The purpose of generating an exploitation plan with gas injection to a reservoir under study is to increase the drainage of existing reserves, in this case, the objective is to reactivate production through existing drainage points or new candidate wells, increasing the reservoir productive life.

Therefore, several sensitivities or cases were performed to reactivate gas injection in this reservoir in the most efficient way possible.

Base Case

In this case, it was proposed to exploit the reservoir under current conditions maintaining production for 15 years, without gas injection to the reservoir, in this period an approximate of 280 KSTB would be recovered (Figure 18), which is not significant with the remaining reserves calculated above and one of the main objectives in the study is to establish an exploitation plan to drain as much as possible of the remaining reserves.

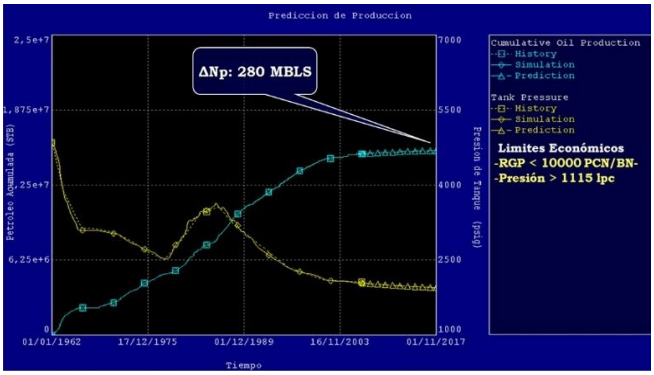

Figure 18. Base Case Forecast.

Case 1

The Base Case was proposed plus the incorporation of 7 wells (1 well requires service, 4 Workovers and 2 new wells) without gas injection, where an economic horizon of 15 years is proposed to exploit the reservoir, bringing into production the wells proposed in the exploitation plan, taking into account that not all of them can be put into production at the same time since, depending on the proposed work, they have a duration to be executed (Figure 19).

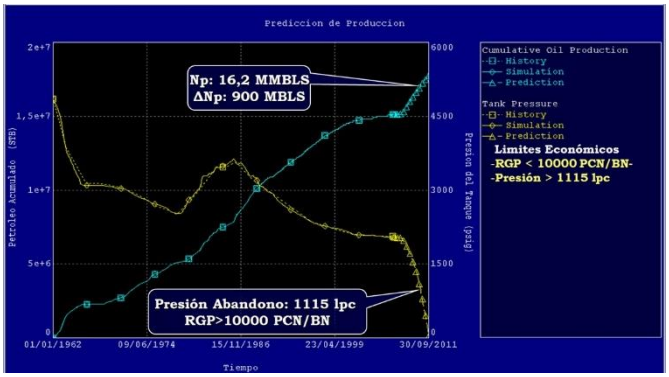

Figure 19. Case 1 Sensitivities.

It is observed that, without gas injection, the pressure drops drastically to the abandonment pressure and the GOR yields values greater than 10000 SCF/STB, with oil recovered of 900 KSTB in approximately 2 years, which is not representative of the remaining reserves of the reservoir.

Case 2

The Base Case was proposed plus the incorporation of 7 wells (1 Well requiring service, 4 Workovers and 2 new wells) with gas injection, the same previous case is proposed maintaining the same established premises, but reactivating the injection of gas to the reservoir, proposing a pressure maintenance period with replacement factor equal to 1, for such case it was needed to inject at 8 MSCF/D, therefore the availability of gas in the area and the capacity of the compressor plants was reviewed being this a manageable volume of gas in the area. The results obtained were satisfactory since it would drain approximately 7.2 MSTB representing 85% of the recoverable reserves, in a period of 15 years, with a GOR lower than the economic limit as shown in Figure 20.

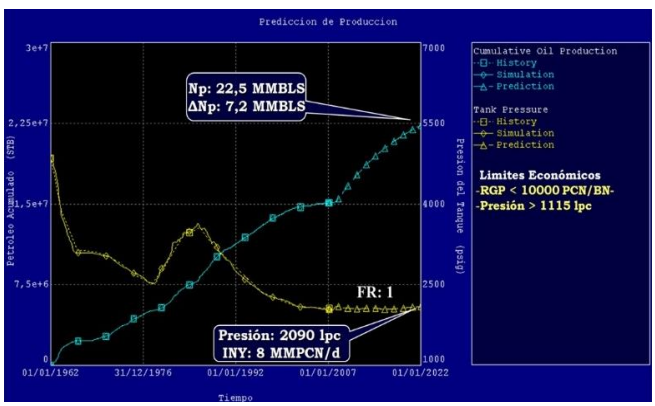

Figure 20. Case 2 Sensitivities.

In the different cases, the advance of the gas front and the OWC were monitored, with the result that the gas front had advanced approximately from 10900 feet to 11050 feet reaching the producing wells in that zone, while the OWC is controlled by the gas injection and its advance was not very significant (See Figure 21).

In gas injection projects as enhanced recovery, we must integrate reservoir engineering with field operations and have a plan to capture information that allows us to have certainty of the data recorded and thus ensure an accurate analysis of the behavior of production injection for this type of project.

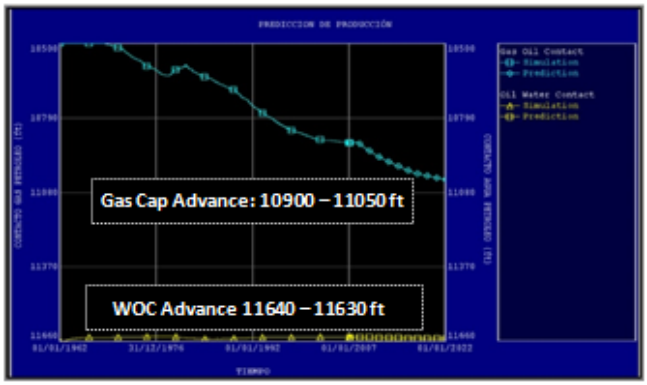

Figure 21. Gas Cap and OWC Advance.

CONCLUSIONS

- The evaluation of the main reservoir parameters in an enhanced hydrocarbon recovery project with gas injection was achieved.

- It was possible to know that the best producing zones and petrophysical properties are located in the central part of the reservoir.

- By this methodology was possible to correct the gas injection parameters during the initial gas injection project.

- This evaluation allows creating a comprehensive philosophy for studies of enhanced recovery projects with gas injection.

- The STOIIP of the reservoir determined by the material balance method was 85.7 MSTB, which presented a difference of less than 5% with respect to the volumetric method of the study and the Official..

- The material balance showed that the aquifer associated with the reservoir is weak.

- The reservoir study allowed estimating recoverable oil reserves of 24 MSTB and remaining reserves of 8.5 MSTB.

- The results obtained by the enhanced oil recovery method with gas injection were satisfactory since it would drain approximately 7.2 MBSTB in a period of 15 years, with a GOR lower than the economic limit.

- Currently the replacement factor to maintain reservoir pressure is at 1.

- The recovery factor estimated by the enhanced oil recovery method with gas injection was 28.5%.

RECOMMENDATIONS

- Conduct a data collection campaign to monitor the pressure behavior of the reservoir.

- Realize an advanced numerical reservoir simulation study to determine the influence caused by gas injection in the new producing wells.

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