Comparison between well test results of vertical and horizontal well on Quissamã Formation, Campos Basin

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Abstract

The main objective of this work is to compare the results obtained in well tests carried on two wells drilled in southern Campos Basin. The wells were tested on the Macaé Group. This group is composed, in the productive zones (Quissamã Formation), mainly by calcarenites, with the presence of dolomites, the facies varying according to depositional conditions, diagenesis, and location inside the basin. Both wells were drilled in the area that formerly belonged to block C-M-592, and nowadays is called the Tubarão Azul Field. The first well is 1-OGX-3-RJS, the wildcat that discovered the field, whose productive zone belongs to Macaé Group. The second well, 9-OGX-26HP-RJS, was drilled as a sidetrack from the 3-OGX-21D-RJS, about 1.2 kilometers northeast of the discoverer, aiming to appraise the discovery and assess the performance of a horizontal well in this reservoir, for a future long-term test. The improvement in productivity verified in the horizontal well test was then compared with some values forecasted by formulas known in the literature, and the deviation from these values was analyzed, with possible reasons presented.

Introduction

The first step in this work was the detailed analysis of the well test data obtained by OGX, operator of these wells in block C-M-592, and sent to ANP with the complete reports, as established by the Concession Contract signed between the two parts.

With this analysis, some formation parameters were obtained, such as permeability, presence of fractures, productivity indexes, besides the skin factor of the wells and the flow regimes of the reservoir to the wells.

The rock and fluid parameters (porosity, water saturation, net thickness, oil shrinkage and compressibilities) used as input data for the analysis were those provided by the Operator at their well and test reports.

Lately, the main discoveries in the central-south region of Campos Basin, shown in Figure 1, were in the Macaé Group, and several wells were tested. Many of these tests were analyzed and some results catch the interpreter attention, as those presented in Warszawski and Ferreira (2011), which showed the great variability in formation parameters along the region.

Even inside the same field, this variability can be remarkable, as was observed in the analysis of the well tests that originated this work. This seems to be the case of the Tubarão Azul Field, shown in Figure 2, with the drilled wells and the trajectory of the horizontal well 9-OGX-26HP-RJS.

In this region, at deep waters, the main prospects' objectives are in the Aptian pre-salt section. At shallow waters, the main objectives are spread between targets in Albian carbonates and Upper Cretaceous sandstones. The results of wells in Albian and Aptian targets largely vary due to occurrence of reservoir facies.

The well 1-OGX-3-RJS is located about 95 km offshore from the coast of the city of Cabo Frio, in Rio de Janeiro state, in water depths of 133 meters. It was drilled between November, 2009 and January, 2010, being tested in February, 2010. Their original main targets were the sandstones of Carapebus Formation (Eocene), and the Macaé Group (Albian) was a secondary target. The well reached a total depth of 4,092.5m, inside the Lagoa Feia Group (Aptian pre-salt), and identified the main hydrocarbon interval in the Albian, from 3,275 to 3,395 meters.

Based on this well results, four appraisal wells were drilled to assess the discovery (3-OGX-21D-RJS, 3-OGX-50D-RJS, 3-OGX-53D-RJS and 3-OGX-65D-RJS), inside an appraisal plan submitted to ANP. From each of these wells, a horizontal sidetrack was drilled (9-OGX-26HP-RJS, 9-OGX-55HP-RJS, 9-OGX-60HP-RJS and 9-OGX-68HP-RJS). All of them were tested and two of these horizontal wells produced in long-term tests, being now connected to the stationary producing unit of the Tubarão Azul Field, OSX-1. This field was declared commercial by OGX in May, 2012, given the results obtained by the appraisal wells.

The well 9-OGX-26HP-RJS is located about 1.2 km northeast of 1-OGX-3-RJS, in similar water depths. It was drilled between November, 2010 and January, 2011, and tested until March, 2011. It reached a total measured depth of 4,746 meters, with a horizontal leg of around 1,000 meters along the reservoir. Its objective was to verify the continuity of the reservoir facies and to be tested, to evaluate the possibility of being equipped for a long-term test. The well was successful in its objectives, and later was submitted to a long-term test. It is producing since February, 2012, starting with an average flow rate of around 1,800 m^3/d (11,300 bbl/day), declining now to around 1,040 m^3/d (6,500 bbl/day). It is been used during this producing time an electrical submersible pump (ESP).

In the next sections, a brief geologic summary of the basin will be presented, as well as the current status of exploratory activities in its central-south portion. Then, the results from well test interpretation for the two wells referred above, used to compare the performance between vertical and horizontal wells, will be detailed. Finally, the conclusions and hypothesis regarding the deviations from the expected results will be discussed.

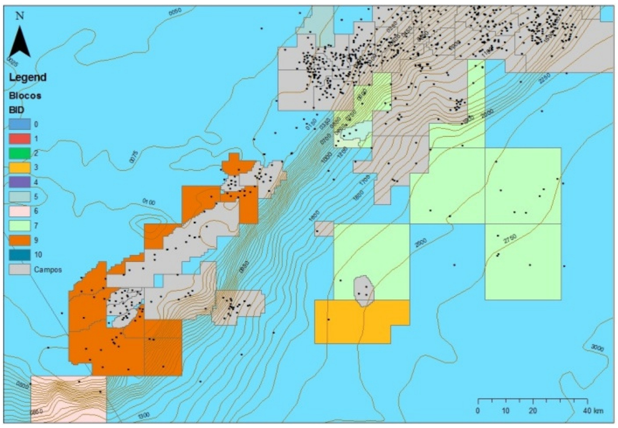

Figure 1 – General map of the central-south part of Campos Basin

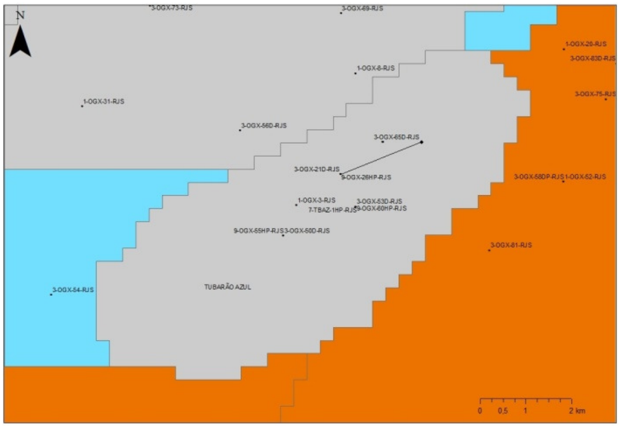

Figure 2 – Map of Tubarão Azul Field, showing the two wells under study, including the horizontal projection of the 9-OGX-26HP-RJS trajectory

Brief geology summary of the basin

The Campos basin is a passive margin basin developed as a result of the Gondwana break up (South Atlantic Ocean opening) in the Early Cretaceous (Rangel and Martins, 1998). Its tectonic evolution begins with the extrusion of Cretaceous basalts over Precambrian pre-existing crystalline rocks, going through a rift phase (lake sedimentation) and followed by a siliciclastic and evaporitic phase that lasted to the Middle Cretaceous. After the Early Albian, an open marine sedimentation phase takes place, lasting to nowadays.

The basin is divided in three main exploratory compartments: proximal, intermediate and distal. The proximal compartment is basically located in shallow waters domain. Its rift section is structurally composed by horsts and grabens with large structural lows, where there is predomination of sections of lagoonal sedimentation with considerable thickness along the whole basin. The initial part of the rift section is generally siliciclastic, followed by a section of coquinas (final phase) with intercalations of lagoonal shales, these latter known as the main source rocks of the basin. The transitional phase is composed of a basal siliciclastic sequence followed by an evaporitic sequence.

Today the majority of the existing salt in the proximal compartment is displaced to deeper waters regions, mainly due to the basculation of basin. In deep water regions these rafting mobilizations affected and structured the open marine sequence, including carbonate turtlebacks and turbidites sands. This latter fact is characterized by an intercalation of siliciclastics and carbonates, both structured by the salt mobilization over structural highs with turbidites close to it. The Tertiary section is composed, from the base to the top, of talus clays with turbidites, passing through coarse platform siliciclastics, intercalation of carbonates and talus clays.

In the transition from shallow to deep waters, the intermediate compartment is by far the one largely investigated by exploratory wells. The main existing oilfields under development and/or under production in the basin are located in this compartment: Marlim, Albacora, Roncador, Barracuda, Espadarte, among others. The main structural features in this compartment are: (1) basement highs and lows, (2) salt pillows affecting the overlying marine sequence, and (3) adiastrophic tectonics caused by the salt mobilization.

The distal compartment is still considered an exploratory frontier. Presently there are several exploratory activities under way in the South and North of the basin. Among these activities, we cite the appraisal of BM-C-33 (Pão de Açúcar and Gávea discoveries, in C-M-539, operated by Repsol Sinopec), the appraisal of Tulum, Viedma, Vesúvio, Peró-Ingá, Tupungato-Tambora and Itacoatiara (operated by OGX), the ongoing development of the Xerelete, now by Total, and the appraisal of the C-M-529 block, operated by Statoil. In the North, we may cite the appraisal of the Wahoo prospect (BM-C-30, operated by Anadarko), the appraisal of the Itauna prospect (BM-C-29, operated by Anadarko) and the appraisal of Itaipu prospect (BM-C-32, operated by BP). In this meantime, five areas were declared as commercial (oilfileds): Tubarão Azul, Tubarão Martelo, Tubarão Tigre and Tubarão Gato (former Pipeline A and Pipeline B), and Tubarão Areia, all these assets belonging to OGX.

The main exploratory reservoirs investigated in the basin are the Carapebus (turbidites), Albian carbonates (Quissamã in shallow and deep waters) and lately, the presalt in deep and ultra-deep waters. These reservoirs play an important role with the source rocks from the rift sequence, linked through adiastrophic listric faults formed due to the rafting of the salt layers.

The main focus of this work is the Macaé Group, specifically concerning the Quissamã Formation. According to Winter et al. (2007), the Quissamã Formation is part of the drift supersequence K60, composed of marine sediments deposited under a thermal subsidence regime associated to adiastrophic tectonism (shallow platform). It corresponds to a distal portion formation, bounded by the Lagoa Feia Group (lower bound, Retiro Formation) and by a regional stratigraphic mark associated with a maximum flooding surface (the beta mark, upper bound). Lithologically, it is mainly represented by moderate to high energy carbonate sediments, composed of oolithic/oncolithic calcarenite banks with "shoaling upwards" profiles reaching up to 15 meters in thickness. The average porosity varies both laterally and in depth. The base of the K60 sequence is mainly composed of a carbonate tidal flat system, ranging in environment to supratidal, intratidal and lagoonal.

Exploratory scenario

The present exploratory scenario in Campos basin, in terms of concession contracts, is extremely dynamic. Currently there are 9 active contracts (March 2013) in the exploration phase, totalizing 11 exploration blocks. There are 49 producing oilfields, while the number of fields under development totalizes 18. In March 2013, 14 appraisal plans were active and under way. The number of wells drilled so far in Campos, including all of its categories (wildcats, appraisal, production, etc), totalize more than 2,780, considering the whole history of exploration of the basin.

In its three exploratory compartments (Rangel and Martins, 1998) – including shallow, deep and ultra-deep waters – Campos basin is largely covered by seismic, potential and electromagnetic data, including well data. Up to now, in terms of Brazil reserves, it is the biggest and most prolific offshore oil producer basin. With the emerging of the new high potential basins, such as Santos and Espírito Santo, Campos Basin may be suppressed in the near future, but in February, 2013, it was still responsible for 82% of the national oil production. However, in late years it still has been proved prolific in terms of several and new exploratory frontiers, with the expansion of exploratory surveys towards deep waters and due also to discoveries in unusual plays.

In the following we update the activities realized in several exploration contracts by diverse operators. The main companies actively acting in this scenario are: Anadarko, BP, Maersk, OGX, Petrobras, Repsol Sinopec, Shell, Starfish and Statoil.

In the North of the basin, in the block C-M-101 (BM-C-30), Anadarko is currently appraising the Wahoo prospect. The Anadarko's block share common boundaries with block C-M-61 (BM-C-32), operated by BP. Its surroundings is composed by several producing oilfields, including the high-potential fields belonging to Parque das Baleias, Parque das Conchas, and also the Frade and Roncador fields.

The surrounding of the C-M-101 block is pointed out here due to its geologic similarities at the level of the exploratory opportunities in the post salt section and, most recently, in the presalt section. In the distal compartment of the basin, either in North or South, the presalt section has been continuously investigated, with all oil companies sometimes deepening the drilling of their wells in order to reach the upper sag or the rift section. This has happened on the contracts BM-C-30 and BM-C-32, in the North, and the contract BM-C-33, in the South.

In the area of the contract BM-C-34, operated by BP, the periods of the exploration of the blocks C-M-471 and C-M-473 were extended by ANP until May/2013 to investigate exploratory opportunities identified in the pre-salt section. This has granted the drilling of important prospects Atobá, Talhamar, Grazina, Fragata and Benedito. With the extension granted by ANP until 2013, at the present moment BP generates expectations towards possible new and huge discoveries at BM-C-34 due to the deepening of its wells in order to reach the presalt section and investigate the prospects Atobá, Grazina and Fragata along C-M-471 and C-M-473, respectively.

In the area of the contract BM-C-33 (C-M-539), the prospects investigated by Repsol Sinopec (Seat, Pão de Açúcar and Gávea) are presently being appraised.

Among all exploration contracts active in Campos basin, we may cite the development of the Tubarão Azul, Tubarão Tigre, Tubarão Gato and Tubarão Areia, located in the South of the basin.

The central part of the basin does not contain active concession contracts in exploration phase, just areas of development and producing oilfields. But, on the other side, inside one active trend of production fields some new discoveries in the Albian Quissamã play have been occurring. We cite that in January/2013 Petrobras declared as commercial the areas of the prospects of Aruanã and Oliva, giving rise to the Tartaruga Verde and Tartaruga Mestiça oilfields.

At the South part of the basin, Brazilian holding OGX currently appraises areas of five contracts: BM-C-39, BM-C-40, BM-C-41, BM-C-42 and BM-C-43, with the following appraisal plans: Itacoatiara, Peró-Ingá, Viedma, Tulum, and Vesúvio.

Recently (March 2013) Petrobras announced that Papaterra field was getting on stream for production next July.

Results

- **1-OGX-3-RJS**

The Quissamã Formation, in this well, was a secondary target, in a faulted elongated structure in NE-SW direction, closed against a fault to the NW. The prospect followed the trend of Albian discoveries inside Maromba Field.

This well was tested in the interval from 3,310 to 3,346 meters (measured depth), in oolitic grainstones of Quissamã Formation, deposited in a high energy environment, over a carbonatic platform. The test was initially composed by 3 drawdown periods, each one followed by a buildup.

The first drawdown period was simply a cleanup. In the second, the oil reached surface about 19.5 hours after its start, and the average flow rate was about 14 m^3/d (88 bbl/day) with a choke opening of 16/64", but unstable and declining along the flow period. In the third drawdown period, N_2 was injected by coil tubing in the test column, and the production was irregular, presenting, in some moments, only the gas injected reaching the surface and, in others, oil. The average oil flow rate was basically the same (about 19.4 m^3/d – 122 bbl/day). The measured oil density was 18.5°API.

After the third buldup period, the well was acidized by bullheading, pumping a total of 316.4 bbl of acid to the formation. As the test results pre-acidification didn't show a damaged interval, the objective of the stimulation was to increase the formation productivity, dissolving the carbonate matrix around the well.

After that, the well was opened, cleaned up and let to flow in a choke size of 1". Again N_2 was injected by coil tubing and a flow rate of 56 m^3/d (352 bbl/day) was obtained.

Analyzing the log-log plot of the buildups, there can be made multiple interpretations. Based on the second buildup (**Figure 3**), there can be inferred a double-porosity regime, followed by a flow barrier or a decrease in transmissibility. The double-porosity behavior is consistent with the fact that the reservoir is composed by calcites and dolomites, where it can be noticed a difference between the contribution to the flow of matrix and fractures. Analyzing the diagnostic plot of the third buildup (**Figure 4**), one can adopt a radial composite model, with a increase in transmissibility further from the well, followed by a flow barrier, or a decrease in transmissibility, for the parameter calculation and analytical model adjust.

Comparing the two plots, it can be noticed that the permeability, in the derivative curve, tend to converge to the same value, but the skin factors are quite different. In the third buildup, it's pretty grater, which can be interpreted as caused by the creation of a damaged zone near well, consistent with the observation made above, about the radial composite flow regime. Maybe in this buildup double-porosity behavior is masked by the presence of this low permeability zone near the well.

Regarding the buildup period started by the shut-in after the drawdown period pos-acidizing, there can be noticed in the diagnostic plot, in the derivative curve, a linear flow feature at the beginning of the period. This is suitable with the stimulation process, and is common in interpretations of many well tests executed in similar situations. This flow regime is characteristic of the reservoir flowing to a vertical fracture, which could have been generated by the acid stimulation carried out before the test. The fracture half-length calculated by the analytical model adjust is short, what reinforce the interpretation that a small fracture is created around the well during acidizing, when the pumping pressure exceeds a bit the one which cause the bottom-hole pressure to be greater than the fracture initiation pressure. The fracture was considered of infinite conductivity, coherent with the fact that the fracturing was made in carbonates, with acid, not using any proppant.

After these considerations, some analytical models were adopted for each buildup and the parameters were calculated, by adjusting of the curves generated by these models, as well as using the specialized plots, for radial flow (Horner plot) and linear flow (square root plot), with the aid of the commercial software PanSystem®.

Table 1 presents a summary of the main reservoir parameters obtained in the well test interpretation.

Buildup Parameters	2 (before acidizing)	3 (before acidizing)	4 (after acidizing)
k (mD)	14.8	8.5	19
DR	0.83	1.0	0.56
PI (m3/d)/(kgf/cm2)	0.29	0.25	0.99
p_i (kgf/cm^2)	342.1	344.5	341.2
Remarks		Increase in mobility around 5m far from the well	Fracture half-lenght of 4.0m and conductivity of 123mD.m

Table 1 – Parameters from well test interpretation of well 1-OGX-3-RJS

The permeability to oil in the region around this well was low to moderate; the well, first, didn't show damage, and after acidification presented an improve in productivity. But, even then, the productivity index can be considered low. There was also a swift gain in permeability, showing that maybe the acidification increased the effective height opened to the well.

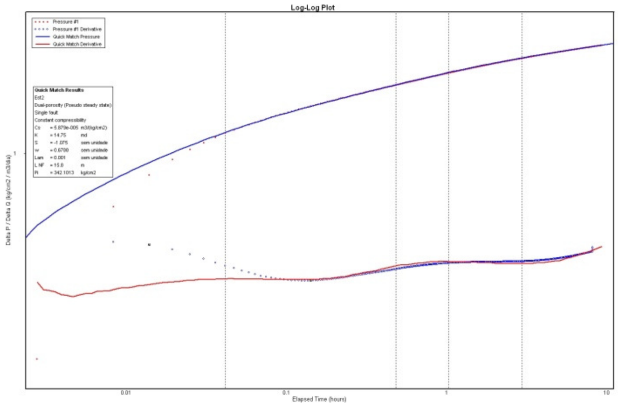

Figure 3 – Log-log plot of the second buildup of well test in 1-OGX-3-RJS, with the adjusted curve

In **Figures 3** to **6**, the log-log plots with the adjusted curves generated by the parameters that were considered better adjusting with the gauge data are shown.

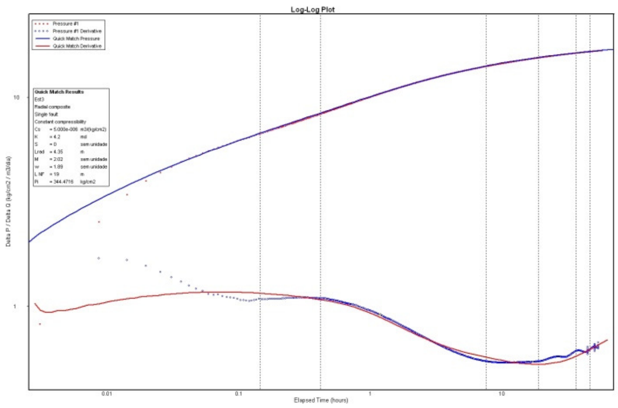

Figure 4 – Log-log plot of the third buildup of well test in 1-OGX-3-RJS, with the adjusted curve

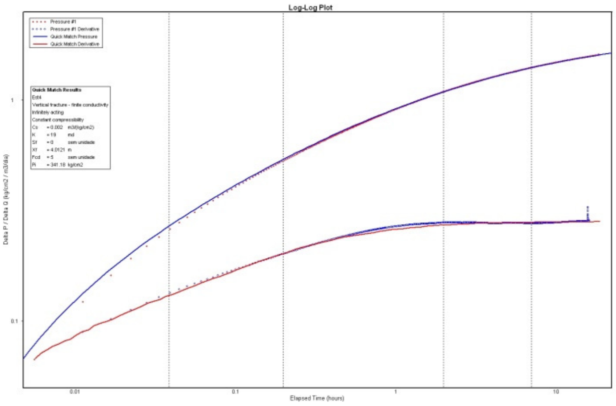

Figure 5 – Log-log plot of the fourth buildup of well test in 1-OGX-3-RJS, with the adjusted curve

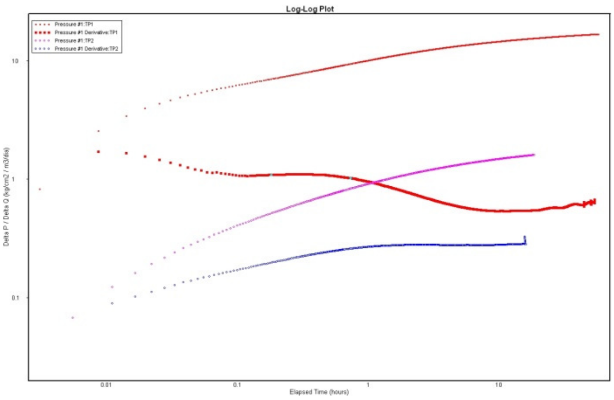

Figure 6 – Log-log plot comparing the buildups before and after acidizing, showing the improvement in permeability and increase of the negative skin

- **9-OGX-26HP-RJS**

This well was tested in the interval from to 3,658.1 to 4,719.6 meters (measured), which corresponds to a horizontal leg in the Macaé Group. The test was composed by a single drawdown period followed by a buildup (**Figure 7** and **Figure 8**).

Several choke sizes were employed during the flow period, in the cleanup such as in the flow rate measurements. In the final opening, of 3/8", the stabilized average liquid flow rate was about 316 m^3/d (1,988 bbl/day), with BSW equal to about 4%. Previously, there was certain stabilization of the flow rate around 667 m^3/d (4,195 bbl/day) with a 5/8" choke opening and around 459 m^3/d (2,887 bbl/day) with a 1/2"choke opening. The measured oil density was 19.5°API.

Before the test, the well was selectively acidized, employing a system with external packers and diverting ports, and using a wash pipe inside the screens. The horizontal length was divided into eight stages, each one stimulated by pumping an average of 50 bbls of acid, just intending to improve the flow near the well.

Analyzing the buildup diagnostic plot, it can be noticed in the derivative curve the presence of an initial trend to horizontal stabilization, which could correspond to a vertical radial flow still not reaching the upper and lower bounds of reservoir. Later, there is a considerable time when the plot fits to a slope of 1/4, characteristic of bilinear flow. This kind of flow regime can be interpreted by being caused by the interception of natural fractures by the well. Another hypothesis for the presence of this flow regime is the non-negligible losses inside the tubing. In this case, there is a linear flow from the formation to the well, as expected (fluid flowing to the horizontal leg), and inside the horizontal length until the fluid reaches the vertical section. After that, there can be noticed a trend in the curve to obey a 1/2 slope, characteristic of linear flow, and finally there is a swift trend to reach the horizontal stabilization, indicating the formation radial flow far from the well, that is called the pseudo-radial flow.

Having made this qualitative analysis, some parameters were calculated in the specialized plots, and after that, a data adjust was made, considering the model of horizontal well with no-flow boundaries as the reservoir upper and lower limits.

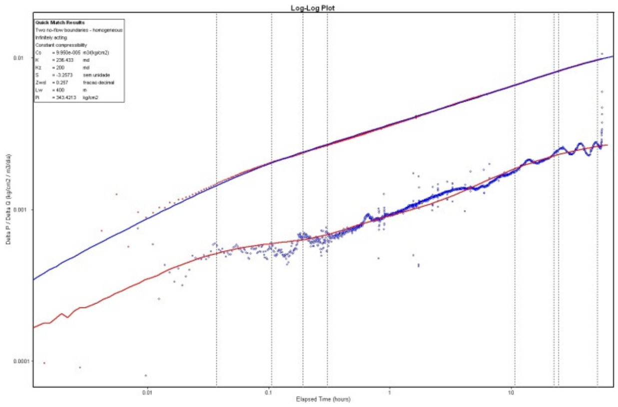

Figure 7 – Log-log plot of the buildup in 9-OGX-26HP-RJS, with the adjusted curve

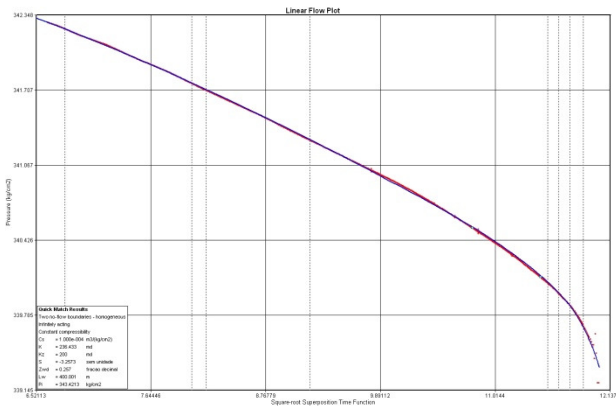

Figure 8 – Linear plot of the buildup in 9-OGX-26HP-RJS, with the adjusted curve

On **Table 2**, the main parameters from well test interpretation of 9-OGX-26HP-RJS are shown.

The permeability for oil estimated from well test interpretation was good, with a negative skin caused not only by the horizontal well geometry itself but also by the acidification prior to the test. The productivity index was greatly enhanced, when compared to the vertical well previously analyzed.

As happened in other cases, in this type of reservoir the productivity can be sharply enhanced by drilling horizontal wells. Besides the usual advantage provided by this type of well, exposing more the well in the formation, it can cross natural vertical fractures, that may substantially increase the productivity.

Permeability (mD)	236
s_{pr}	-6
Productivity Index (m3/d)/(kgf/cm2)	79.2
Static pressure (kgf/cm^2)	343.2
Remarks	Horizontal length contributing to the flow between 400 and 600m

Table 2 – Parameters from well test interpretation of well 9-OGX-26HP-RJS

- **Study of the fold of increase (FOI)**

It is well known that theoretically a horizontal well can deliver a greater productivity index (PI) than a vertical well in the same reservoir. The main reason is that the area of reservoir exposed to the well is greater, and as the losses inside the well are much lesser than the losses suffered by the fluid in the reservoir rock, the decay of pressure around the well is smaller for the same flow rate, increasing the productivity index. The advantage is greater as the reservoir is thinner, compared to the horizontal well length. The reason between the productivity index of the horizontal well and that of the vertical well can be referred as the fold of increase (FOI).

There are some equations derived mainly from empirical observations, known in the literature, that try to forecast the PI provided by horizontal wells, given well and reservoir parameters. In general the results provided by them are not very different from each other.

Some of these equations were employed to compare the forecasted FOI (after calculating the theoretical PI for the vertical well) with the calculated through the measured PI's of the vertical and horizontal well. Below, some of the equations are presented.

Borisov (1964):

$$PI = \frac{2\pi k_h h}{B\mu\{ln(4r_{eh}/L) + (h/L)ln[h/(2\pi r_w)]\}}$$

Giger (1983):

$$PI = \frac{2\pi k_h L}{B\mu\left\{(L/h)ln\left[\frac{1+\sqrt{1-[L/(2r_{eh})]^2}}{L/(2r_{eh})}\right] + ln[h/(2\pi r_w)]\right\}}$$

Joshi (1988):

$$PI = \frac{2\pi k_h h}{B\mu\left\{ln\left[\frac{a+\sqrt{a^2-(L/2)^2}}{L/2}\right] + (h/L)ln[h/(2\pi r_w)]\right\}}$$

$$a = (L/2)\left[0.5 + \sqrt{0.25 + (2r_{eh}/L)^4}\right]^{0.5}$$

Mutalik et al (1988):

$$PI = \frac{2\pi k_h h}{B\mu[ln(r_e'/r_w) - A' + s_m + s_f + s_{CA,h} - 1.386]}$$

In the equations above, k_h refers to the mean horizontal permeability, B is the oil formation-volume factor, μ the viscosity, L the length of the horizontal leg, *h* the net pay, r_w the well radius, r_{eh} the equivalent drainage radius of the horizontal well, A' = 0.738 for a drainage area approximately rectangular, s_m is the mechanical skin factor, s_f the skin factor due to a infinite conductivity fracture and half-length equal to L ($s_f = -ln[L/(4r_w)]$) and $s_{CA,h}$ is given by a table provided in Mutalik et al (1988).

Using the equations above, the values shown in **Table 3** were obtained.

Equation	FOI
Borisov	4.56
Giger	4.65
Joshi	6.35
Mutalik	3.64
Pseudo-radial flow equation	7.19

Table 3 – Values of FOI obtained by empirical and analytical equations

The FOI calculated through the calculated values of the productivity indexes arisen from well test data is 80.

- **Other wells**

There were other horizontal wells drilled in the region, whose data are still confidential, that didn't show the same amount of improvement in the productivity index. Some of them were not even close to that obtained by 9-OGX-26HP-RJS well, although similar horizontal length and reservoir thickness.

This shows the great variability in reservoir parameters that must be taken into account when modeling the reservoir, locating the wells and predicting the production.

Conclusions

The improvement in the productivity index of the horizontal well, compared to the calculated for the vertical well, was much greater than that forecasted by the analytical and empirical formulas.

Some reasons can be used to explain this better improvement.

First, the empirical equations were developed for permanent or pseudo-permanent flow, when the flow reaches the boundaries of the reservoir, or the boundaries of the well drainage area. In the wells tests, the flow was still in the transient regime. But, even considering these assumptions, the difference should not be as large as the verified in this work.

Probably, the main factor is because the horizontal well was not drilled in the same location of the tested vertical well. Thus, the region where it was drilled can simply have better permo-porosity features than that where the vertical well was drilled, what is very common, especially when dealing with carbonate reservoirs. This conclusion is corroborated by the value of permeability obtained in well test analysis, and indicates a great lateral variability in this reservoir.

Besides that, the horizontal well may have crossed natural fractures along its stretch along the reservoir. Again, especially in carbonate reservoirs, the influence of natural fractures in fluid flow is huge. As this kind of reservoir present a great lateral variability, the horizontal well can reach zones with different permeabilities and fractures densities, thus obtaining better results, mainly in reservoirs not so thick.

There are reported cases where the effect was the opposite. The horizontal well showed a result worse than planned, because of not finding the expected facies.

Acknowledgments

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