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MULTIDISCIPLINARY VISION IS THE KEY TO MAKING A HIGH STRATIGRAPHIC AND STRUCTURAL COMPLEXITY OIL FIELD PROFITABLE UNDER AN ADVERSE COSTS SCENARIO

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Abstract

INTRODUCTION: The field studied is an onshore producer of oil and non-associated gas. The high compartmentation degree, the reservoirs situated at great depths, the economic factors (costs *x* product prices) are of crucial importance for its economic feasibility. The strong production decline motivated this study. **OBJECTIVE:** To investigate the main causes of the actual accentuated production decline. To present technical/economic workover operations for the small reservoir volumes with low Recovery Factor (RF), once they represent 92% of the total reservoirs and approximately 50% of the field Volume and to propose of a new criterion for well locations in the field. **METHOD:** Longitudinal and Cross-sectional study on an onshore oil/gas field in a Northeast basin of Brazil. The authors surveyed a more than 30 years period production history in the Production Information System of the company and observed the variables referred to the year 2016. They took in account the Field Development Plan Reserves and the Reservoirs Information System. They conducted a data descriptive statistics analysis and interpreted the interaction between intrinsic and conjuncture field factors. They tried to establish a relation of cause and effect between the referred factors and the accentuated production decline. **RESULTS:** The current strong oil production decline of the field do not have fortuitous cause on the contrary, we expected them. The field is extremely dependent on low cost workover operations for being economical feasible under an adverse costs and sale price scenario. The firsts would be an alternative to the conventional perforating, Tubing Conveyed Perforating Tools (TCP) with extreme under-balance, and formation hydraulic stimulation operation due to their high costs. Finally, the drilling of new wells is economically feasible if, only if the current criteria for oil well location (based on the results of the previous ones in areas of high drilling density) is substituted for a new one. **CONCLUSIONS:** The strong oil field production decline is due to its production history, unfavorable conjuncture of rig costs and sale price, oil field geology extremely adverse: deep reservoirs, the majority of the reservoirs (92%) are smaller than 150,000 m³ (≈ 943,000 bbl) high reservoirs water saturation, reservoir pressure and fluid contact individualized for each of them. The lateral jetting would be an alternative of low cost workover operations for make economically viable the numerous small accumulations presenting low RF. This technique would take advantage of two favorable aspects of this oil field with respect to the others: great quantity of stacked reservoirs and the high compaction degree of the reservoir rocks avoiding the well jetting legs to collapse. A new 3D seismic acquisition, with specific parametrization, aiming to illuminate areas with little information and improve the resolution in the other areas must support the new criteria to propose well locations making them economically viable.

1. Introduction

1.1. Presentation of the Oil Field

The oil field studied is an onshore oil and gas producer from sandstone reservoirs with sedimentation predominant fluvial e deltaic during the Early Cretaceous. Despite the fact that the wildcat well produced gas, today its

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main produced fluid is oil. Until now, this first exploratory well is still producing and has a gas cumulative production around 1,031 MM m³. On other hand, during this same year another exploratory well discovered oil in the sandstones from the main oil producer reservoir. In total, the field has about thirty exploratory wells and two 3D seismic acquisitions.

1.2. Stratigraphy and Reservoirs

The reservoirs take part in a more than 4,000 m of stacked sediments: Deltaic, Fluvial, and Aeolian sediment. They form more than 100 stratigraphic independent zones. They are sandstones with 12% to 25% porosity and permeability varying from 3 mD to 166 mD.

1.3. The Oil Field Structure

The field is a great anticlinal structure. The structure apex is intensely failed which produced a high compartmentation of reservoirs. The field is divided into two distinct compartment: the South compartment (Principal) where are located the main reservoirs and the North Compartment, separated by a transfer zone.

1.4. The Relevance of the Field

This field is of great importance because its Original Oil in Place (OOIP) and Original Gas in Place (OGIP) represent a half of the respective volumes of the Production Asset where it is located. In the context of Operational Unit where its Production Asset is, its gas has an importance greater than the oil importance: the greatest OGIP and second in the ranking of proved reserve. On other hand, has an important participation in the gas and natural gas liquid (NGL) production of its Production Asset and Operational Unit.

It also assumes an importance in Brazil Northeast gas production context. It contributes greatly to meet the demand of the thermoelectric orders (Brazil energetic matrix) during the current period of energy sector crisis that still spans a long period due to lack of rainfall. As well as to meet the consumption of natural gas by the industries in this region for a long time, gas lower demand made the field produce according to the demand curve, in this way, below the wells production potential. Lately, the field has had difficulties in meeting the gas demand even producing in their full potential due to the events mentioned at the beginning of this paragraph (later we will talk more about it).

Such is the importance of this oil field in relation to gas that Petrobras gas strategy even studied on the viability of storing in the depleted reservoirs of this field gas imported from the Middle East vessels in the form of NGL. This field became interesting because besides having reservoirs with a high degree of depletion and good characteristics of storage, it did not present any kind of environmental restrictions once it is an onshore field and its reservoirs are at great depths.

The relevance of the study is due to the large fluctuations in gas demand due to the inputs of the thermoelectric power stations. The cyclical demand without periods of defined duration (irregular rainfall), long distance provider that is located in the Middle East (the gas takes a month to arrive) and the fact of the gas must be discharged immediately upon arrival at the Terminal reinforces the importance of the cited study.

This oil field is the third greater OOIP and the fourth cumulative produced oil volume among the onshore fields of its Operational Unit. It is the sixth position in the proved reserve ranking in its operational unit and has the same position when we talk about total oil reserve.

1.5. Oil Field Development

The first drilling campaign comprised 158 wells and it happened from Dec/81 to Mar/90 (Figure 1) and culminated in the highest peak of production of its history (Qom = 1,352 m³/d or 8,503.8 bpd in May/86). We call attention to the fact that the first campaign exploitation model was based on vertical wells: 139 vertical and 10 directional wells; 03 wells in an adjacent area (one of them is directional); 05 vertical wells in a second adjacent area vertical and finally, 01 vertical well in a third different area contiguous to the ring fence.

With the suspension of well drilling (no well was drilled from April/90 to June/98), the field experienced a strong production decline due to the lack of new production intervals entry propitiated by new wells. This production decline only began to alleviate in 1990 with the water and gas injection secondary recovery start (Figure 1). A first study on secondary recovery in Oct/86 involving the 06 major reservoirs (30% of OOIP) recommended water injection to begin in Jan/88. Delay, by operational problems, required a revision of the 1988 simulation study: this time the study recommended as the best option to the recovery factor, simultaneously inject gas and water.

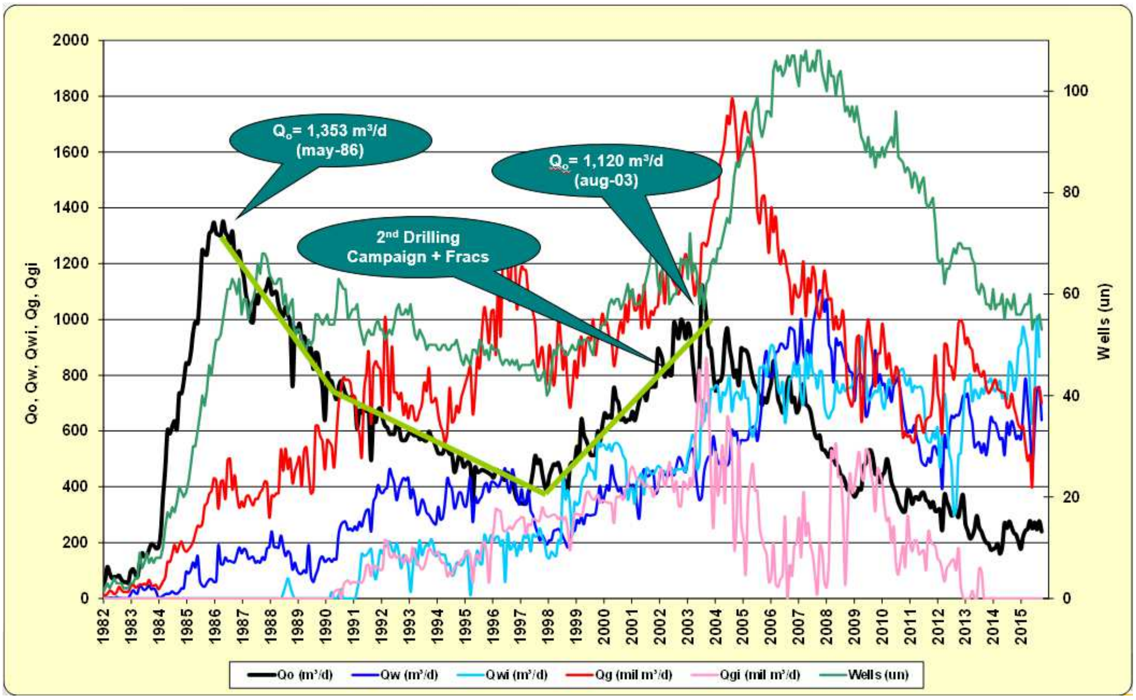

Figure 1. Oil Field Production and Injection History.

In this drilling off-season (Apr/90 to Jun/98) driven by strong field production decline were held two 3D seismic acquisitions enabling the mapping of various seismic horizons along the field: one acquisition in 1994 especially in areas with low density of wells and another in 2002 in the north area of the field.

The 3D seismic acquired in 1994 brought a strong contribution to the field geological reinterpretation and geometric modeling of its sealant faults plane allowing to confirm the geological model of the main compartment. There was a considerable gain of information in areas with low well density especially in the Southeast area. In areas with higher density of wells or poor seismic prevailed interpretations based on well data supplemented with production data.

The geological reinterpretation and geometric modeling of the field sealing fault plane propitiated by the acquisition of 3D seismic in 1994 allowed the development of a Second Exploitation Model in Jul/98 that consisted in planned directional wells aiming the accumulations trends produced by faults. A second drilling campaign of 40 parallel directional wells to the fault plane associated with hydraulic fracturing led to a reversal of the production decline. This time the field reached its second peak of production equivalent to 1,120 m³/d (7,045 bpd) in Aug/03 something close to the first peak of the first drilling campaign (Figure 1). In this new model of directional wells, carefully planned trajectories through known reservoirs mitigated the drilling risks in discovering new reservoirs (Borba *et al.*, 2004).

The gas injection that the previous studies and applications proved to be more efficient has not been operated in years due to the gas unavailability (power plants demand). On the other hand, the water injection expansion occurred in 2010 has not yet shown results good enough to reverse the field production decline. It consists of changing from oil producer wells to water injection wells avoiding the high costs of drilling new injectors. We are also about to accomplish the implementation of a second water injection project in the field.

1.6. Motivation

The accentuated production decline through which the field has undergone in recent years due to the results far below than expected from the last drilled oil wells and to the adverse scenario of rig costs and products sale prices that make economically inviable small volumes motivated this work.

1.7. Objective

This work aims to raise the main causes of the strong decline in current oil field production and to propose technical/economic viable alternatives for small accumulations with low RF once they represent 92% of the reservoirs and account for about half of the OOIP of the field. Finally, it proposes new criteria for choosing economically viable locations.

2. Methods

This is a longitudinal study on onshore field of oil and gas in a Brazil Northeast basin. The authors consulted more than 30 years of history production in the Production Information System. In addition to the Development Plan, they consulted the Reservoirs and Reserve Information System. They accomplished a descriptive statistical analysis and an interpretation on the interaction between the intrinsic factors to the field (more details downwards) and conjuncture factors acting in the field, trying to stablish a cause and effect relationship between these factors and the current strong field production decline. The authors compare the production performance of the wells and reservoirs in the field. They raised the following costs: workover operations, well drilling, daily rates of drilling rigs, onshore production rigs in addition to the production operating costs. Another object of the work was the performance of water injection.

3. Results and Discussion

This field features various "Intrinsic Factors" (inherent to the rock-fluid system) that can contribute positively or not to the final recovery factor of the field. On the other hand, a range of "Conjuncture Factors" (connected to the environment) can act contrary or not to the first ones. We set out below the Intrinsic Factors and the Conjuncture Factors. Then, we try to establish a cause and fact relationship between them and the low recovery factor and the current accentuated field production decline.

3.1. Intrinsic factors

The intrinsic factors are: a) high stratigraphic complexity; b) high structural complexity; c) reservoirs of low slope (average=7º); d) high water saturation reservoirs (initial saturation or resulting from the reservoirs production); e) excellent vertical water permeability; f) high depth reservoirs; g) accentuated variation in the water formation salinization degree from the upper portion of the producer formation; h) great pressure variation among the reservoirs; i) excellent oil quality; j) large volume of gas in deep reservoirs. Next, we will better detail each of these factors:

a) The high stratigraphic complexity (Figure 2) of the main oil bearing formation is a result of fluvial-deltaic depositional environment controlled by tectonics and climate. The tectonic pulses and climate variations produced frequent fluctuations in the lake level, resulting in interbedded sandstones reservoirs and capping shales, that is, disconnected reservoirs (Falconi, 1990).

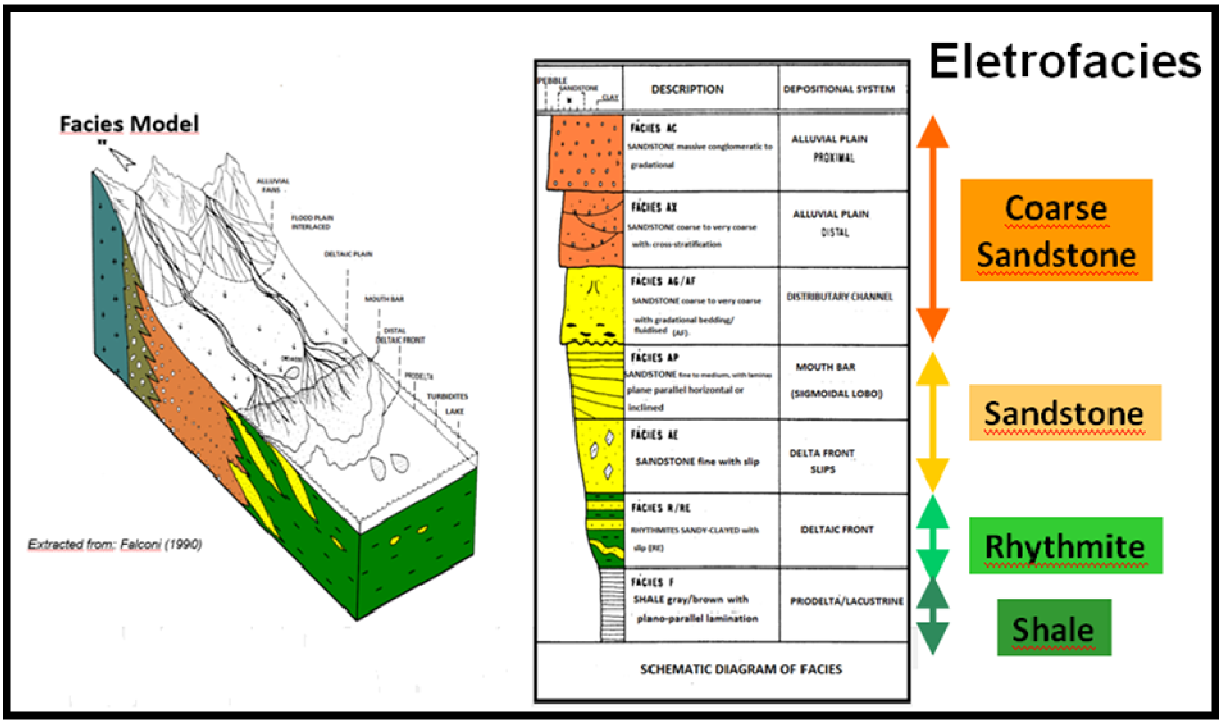

Figure 2. Facies Model.

b) The high structural complexity is due to multiphase tectonics that deformed sediment layer deposited at an earlier stage. The result is the large number of faults, up to 500 m fault slip, with sealing characteristics. They are responsible for the intense partitioning of the field (Figure 3) and a large number of small accumulations. The Faults have influence on reservoir drainage strategy, with recompletions from the bottom up (Weidmann, 1987).

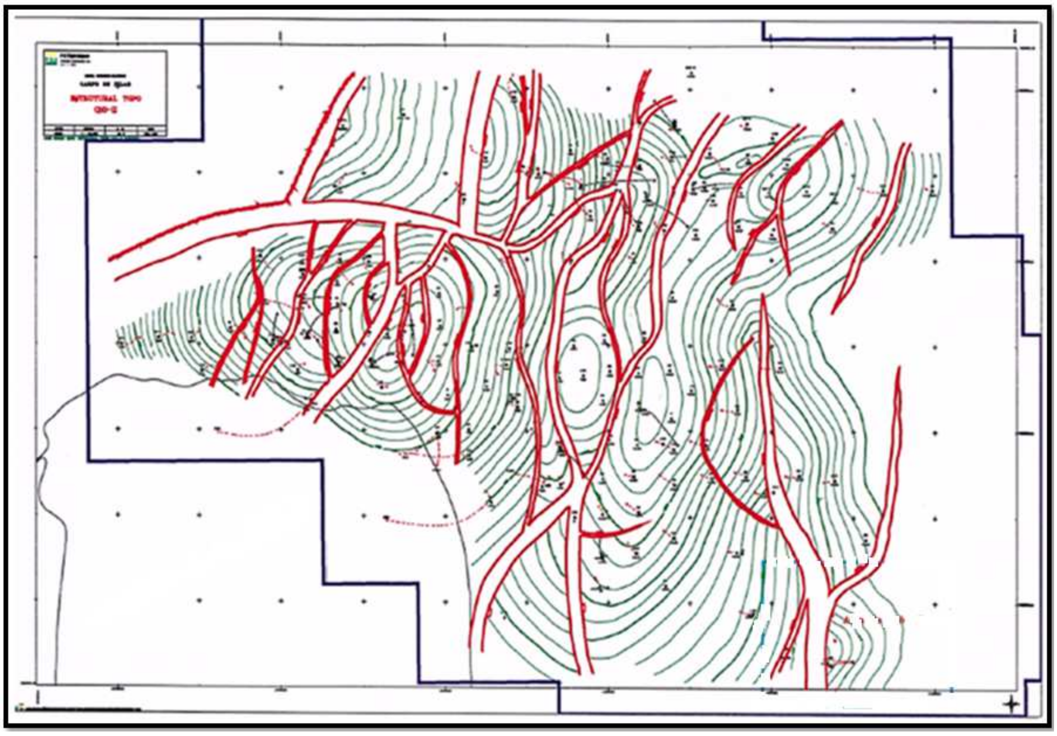

Figure 3. Structural map at a given horizon based on 3D seismic and wells.

The large number of small accumulations (Figure 4) has each one their own contacts and individualized pressures (900 production zones registered in the Reserves and Reservoirs System). Of the 621 oil zones, 428 resulted producers so far. Of the 279 Gas zones, 103 resulted producers.

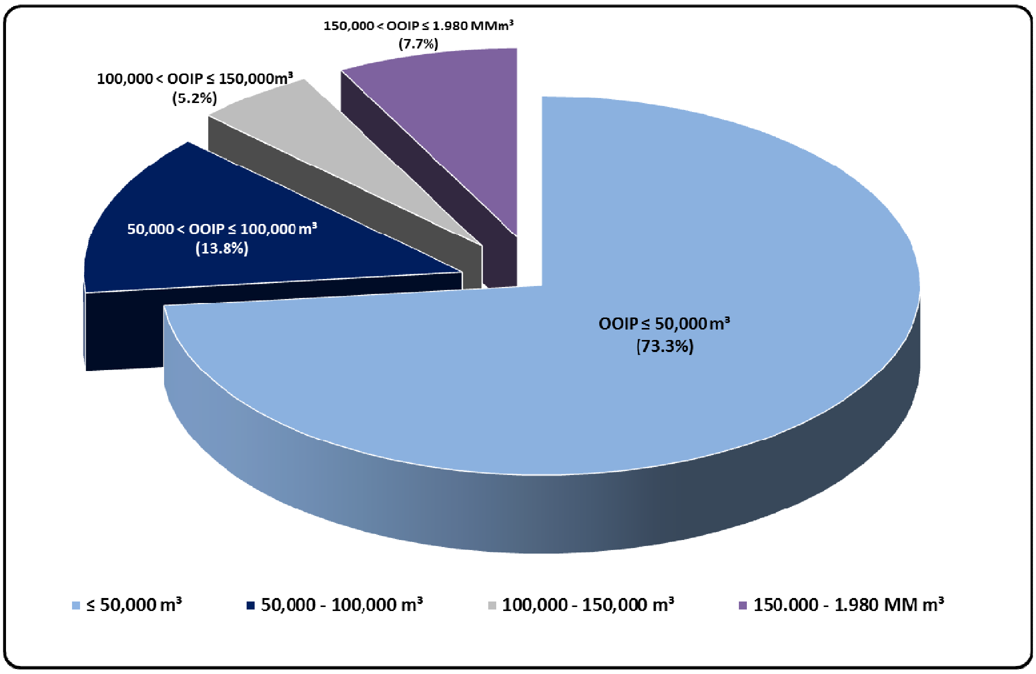

Figure 4. Reservoirs distribution according to OOIP.

As shown in the Figure 4 above, most of the field reservoirs has a small volume, that is, less than 50,000 m³ (n = 455; 73.3% of the field reservoirs). Of the 166 remaining reservoirs, 118 (19%) have volumes between 50,000 and 150,000 m³ and only 48 (7.7%) have volumes larger than 150,000 m³.

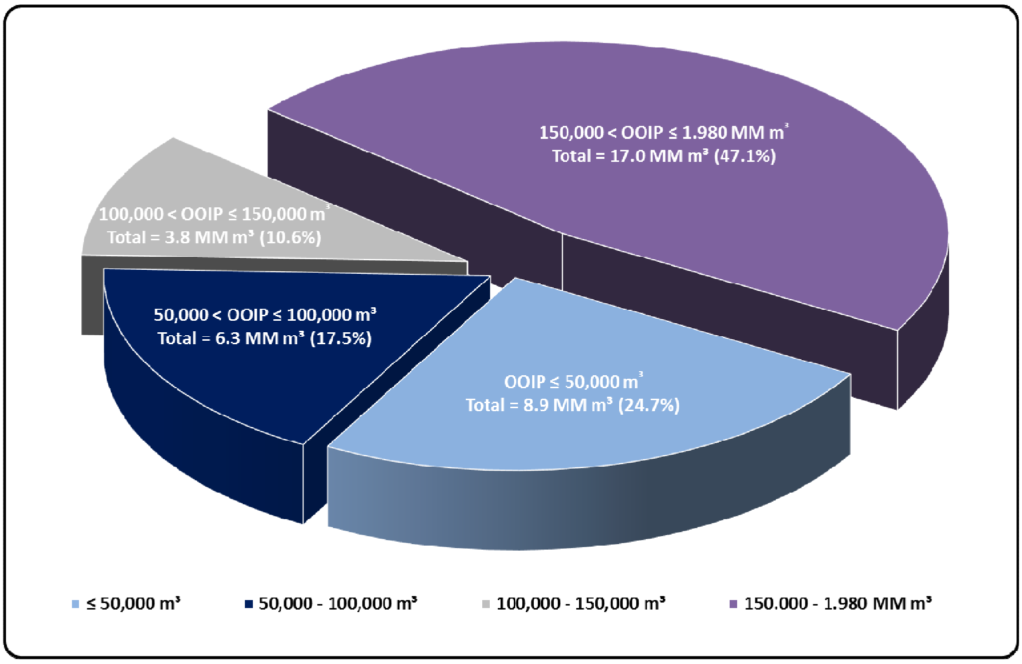

Figure 5. Participation rate of reservoirs classes in the field OOIP.

Figures 4 and 5 above suggest that although the reservoirs with small volumes (< 50,000 m³) are the most numerous (73.3% of the total) they only correspond to approximately a quarter of the field OOIP. At the other extreme, reservoirs with larger volumes (> 150,000 m³ and < 1,980,000 m³), despite the fact they are few (7.7% of the total) they correspond to nearly half of the field OOIP (47.1 %). In addition, the reservoirs with volumes between 50,000 m³ and 150,000 m³ represent 19% of the field reservoirs and participate in almost a third of the field OOIP (28.1%).

In Figure 6, the performance of each of the reservoirs classes through their participation in the field cumulative produced oil volume.

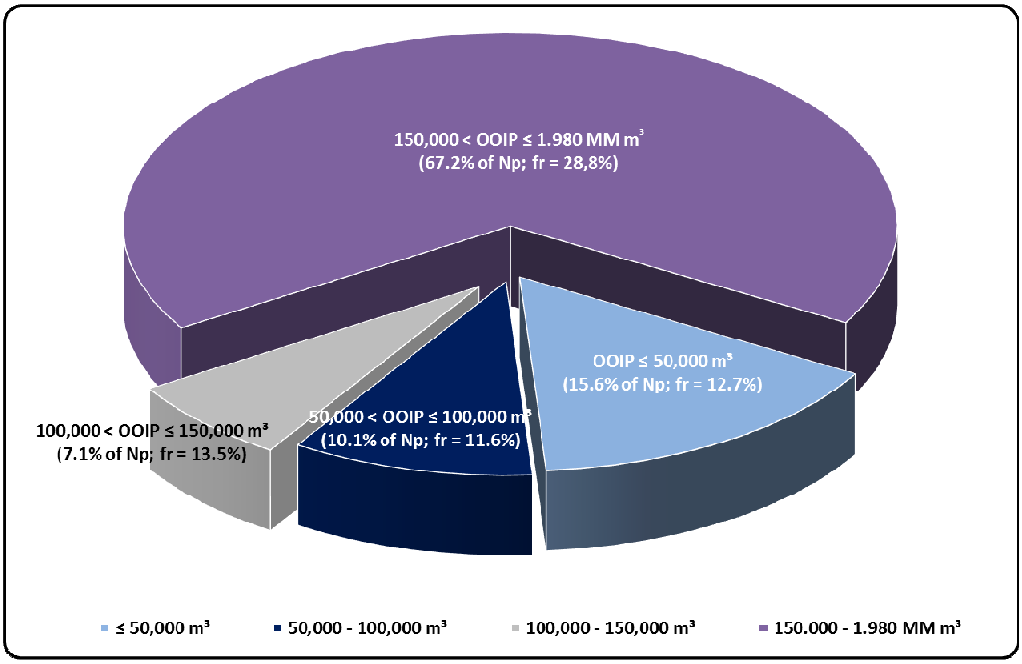

Figure 6. Reservoirs distribution according to cumulative produced oil volume (Np).

We observe in Figure 6 it is precisely the largest reservoirs (VOIP > 150,000 m³), although they are few (7.7%), they have a higher share of cumulative produced oil volume of the field (67.2%) and consequently a higher recovered fraction (fr = 28.8%). On the other hand, the smaller volume reservoirs (OOIP < 50,000 m³), although they are most numerous (73.3%) have a low fr (12.7%) compared to that group of greater reservoir volume.

c) Reservoir low inclination (average slope = 7º) is a determining factor for closer Oil/Water contact mainly in the reservoirs with smaller volume / thickness. See Figure 7 below by way of illustration.

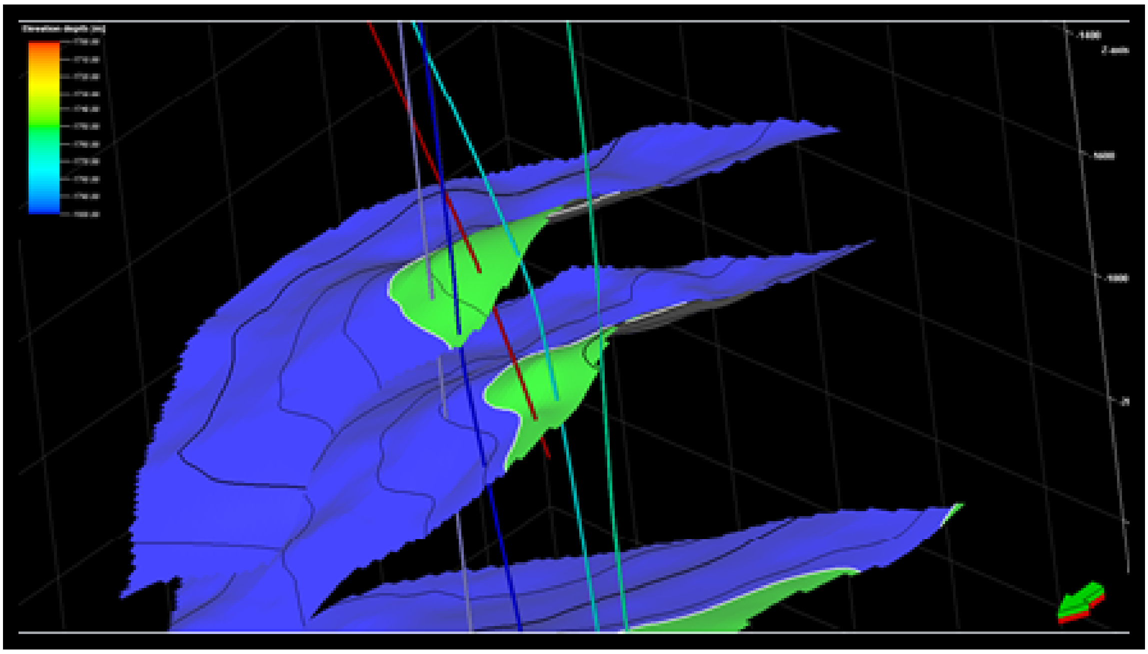

Figure 7. Top surphace 3D-viewing of producer zones in the field.

d) The reservoirs have high water saturation (original or resulting from the reservoirs production) at all depths as shown in the structural cross section in Figure 8 below.

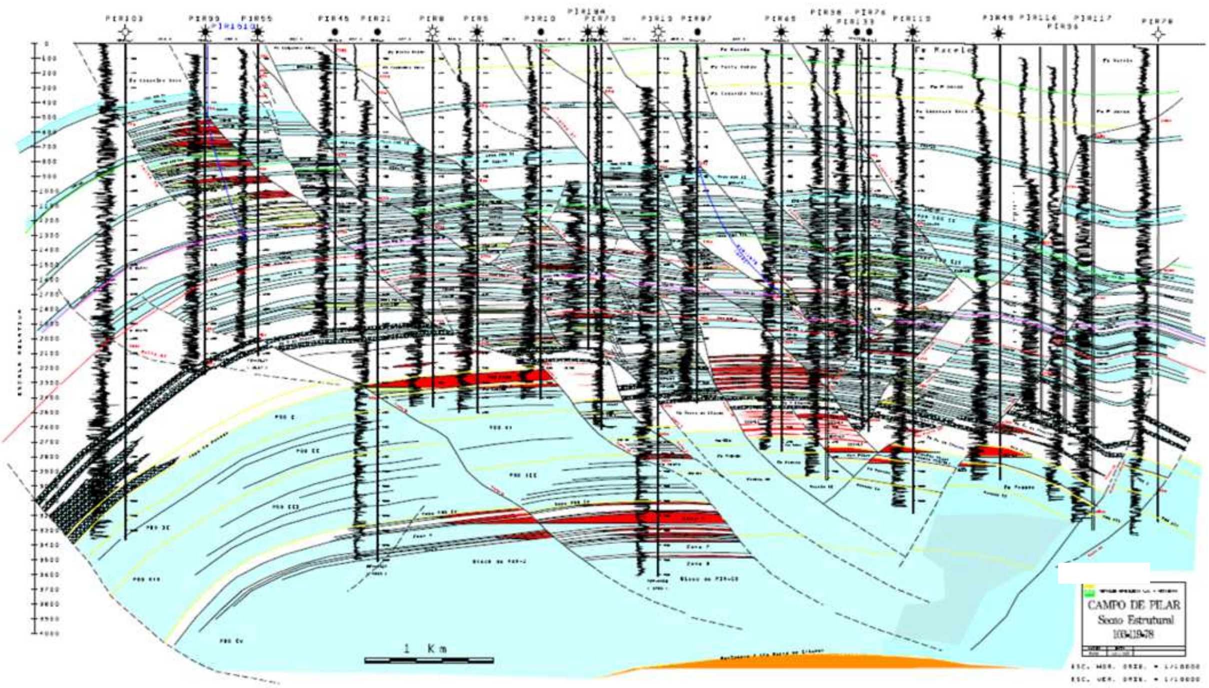

Figure 8. Structural cross section through the south compartment of the field.

This occurrence enhances the risks of putting into production the intervals that supposedly bear hydrocarbons especially if the reservoirs volumes involved are small. The same goes for the risks involved in drilling, since the well must pass through the structure maintaining a reasonable distance not to cross the fault, but not so far from it avoiding crossing the structure below the oil / water contact. Smaller is the volume, smaller is the oil ring, increasing the chance of drilling failure (Fernandes, 2012). It is important to note that each reservoir is hydraulically disconnected from each other, thus each presenting different oil / water contact.

e) The reservoirs have good water vertical permeability, which provides a rapid rise in the contact Oil/Water or the water rise in cone (waterconing). The lower the volume of the drained reservoir is, the faster the water will hit the perforation. It is interesting to point out that the cone regression in the larger volume reservoirs after a period of production shutdown has brought considerable additional volume produced when the well returns to produce.

f) The great depth of the gas/oil reservoirs, in itself, is responsible for drilling wells and workover operations more time-consuming. Following, average depths of reservoirs from the field:

900/2,800 m: Formation A (main fluid: oil)
~ 3,400 m: Formation B (main fluid: gas)
~ 4,100 m: Formation C (main fluid: gas)

g) The accentuated variation in the formation water salinity degree from the upper intervals of the field occurs both areal and vertically. There are areas of the field where the rainwater reached great depths, resulting in low salinity gradients until depths greater than 1,000 m. These areas are located in the western portion of the field, near the recharge area and in the regions where the most superficial formation is eroded consequently facilitating the seepage of meteoric water. The field has three and well defined different salinity gradients to depths of up to 1,000 m. Under the depth of -1,400 m, the gradient becomes only one, not existing the influence of meteoric water. The low salinity degree of the formation water which occurs up to the depth of -1,000 m creates a difficulty to the interpretation of fluids contained therein, once the open-hole conventional resistivity logging is not conclusive. This justifies the fact that the shallower reservoirs zones have been little investigated until now due to risk aversion.

h) The first major cause of pressure diversity among reservoirs is the high stratigraphic and structural compartmentalization degree. On the other hand, two more reservoir characteristics are associated with this diversity: the large reservoir depth variation and also their different depletion degrees. This pressure diversity impacts a lot in drainage strategy since we cannot frequently produce more than one small volume reservoirs together due to the pressure differences among them (they don't allow workovers with a single completion fluid).

i) The oil is of excellent quality and has an average density of 39° API at 20° C and viscosity of 1 cp (200º F). The pour point ranges from 15 to 33° C. The paraffinic hydrocarbon / aromatic ratio (KUOP) is about 12. The content of asphaltenes is low (< 1°) as well as the acid index (< 1). This excellent quality is a competitive factor because gives more value to the product helping to make economically viable smaller hydrocarbon accumulations.

j) There is a large amount of gas in deep reservoirs of two other formations that are main producers of gas in the studied field (Formation B and C). This associated with a strong thermoelectric demand due to the energy crisis caused by the shortage of rainfall increasingly make possible to diversify the field portfolio adding new projects aiming the production of the non-associated gas. As an example, the largest reservoir in Formations B has currently a cumulative produced gas volume of about 1,000 MM m³.

3.2. Conjuncture Factors

Among the Conjuncture Factors are: a) high daily rate of drilling rigs and onshore production rigs; b) high production unit costs; c) well equipment and production casing conditions; d) oil and gas sell prices; e) Gas market demand for gas. Following, more details of these factors:

a) The daily rates of drilling rigs and also of onshore production rigs that work nowadays in the field showed a growth trend with the oil price and are currently in very high levels.

This diminishes the profitability of the largest hydrocarbon accumulations and makes economically inviable the smaller ones that are majority in the field.

b) Not only the cost of rigs has increased, but also the field production unit costs reflecting the conjuncture increase in the inputs costs: material, equipment, services. This will also impact the economical viability of small volumes.

c) The condition of the well casing and well equipments may be a complicating factor for the well workover operations. There are wells that can be up to more than 30 years drilled. This may result in time consuming operations both due to the fishing risks and the high number of operations involved to reach the desired interval: number of well equipments to be recovered and cement squeezes to be drilled.

d) The field products sell prices belong to a class very valued in relation to BRENT due to the good oil quality.

e) The gas Market demand in Brazil Northeast makes increasingly possible to diversify the field portfolio through adding non-associated gas projects. The gas can be produced in the full potential of reservoir differently of many years ago when it was produced under a forced demand curve. This increase in gas demand occurred to meet the accentuated thermoeletric power plants demands (lack of rainfall caused by climatic events) and also to meet the natural gas demand in Brazil Northeast.

4. Data Interpretation and Results

From the ten Intrinsic Factors mentioned in Section 3, eight help to explain the strong production decline and the consequent moderate recovery fraction (22.3%) and low RF (25%) of the field. They are: high stratigraphic complexity; high structural complexity; reservoir high water saturation at all depths; faults proximity in relation to the wells and close oil/water contact; hydrocarbon accumulations at great depths; accentuated variation in formation waters salinization degree of the upper portion of the field; great variation among the reservoirs' pressures; good water vertical permeability reservoirs. In generally they hinder, as previously shown, the economical viability of small volumes that are mostly in the field negatively impacting in this way the Recovery Factor and field production decline as a whole. The mechanisms they act are described in Section 3 in each of the subsections dedicated to them.

Only two of the ten Intrinsic Factors contribute to increase FR but they are not, however, sufficient to overcome the negative effects of the eight ones mentioned above. They are: excellent oil quality and the existence of a large amount of gas in deep reservoirs.

On the other hand, among the five Conjuncture Factors, only three contribute negatively to the FR and therefore to accentuate the production decline: high daily rate of the drilling rigs and onshore production rig; high production unit costs; conditions of casing and equipment of the wells that can be up to more than 30 years drilled.

However 02 Conjuncture Factors contribute to increased FR: the products sale price; the gas Market demand. The mechanisms they act are also described in the Section 3 in each of the subsections dedicated to them. In a Joint factor analysis, the well drilling costs in the field due to high drilling rates associated with long-term well construction is largely making unfeasible small hydrocarbon accumulations that are mostly (73.3%) in the field (the greater is the depth the harder is for the economical viability). In addition to this, the very high production unit costs that is also close to the products sell price (very low the currently) results in a very tight profit margin to make the small hydrocarbon volumes economical viable.

These small accumulations located at greater depths often cannot be made economical viable by Workover operation (change of producer intervals) due to: the high operational costs resulting from high daily rates of the onshore production rigs and long-term rig operations due to the high intervals depths involved.

With regard to secondary recovery, the reservoirs that showed the higher RF were those with OOIP greater than 200,000 m³ and that were submitted to water and/or gas injection. Small accumulations associated with great depths, high daily rates rigs do not pay drilling new injection wells to establish a suitable injection pattern. On the other hand, there are few wells producing oil in these reservoirs that are in a suitable position to be changed from producers to injectors taking advantage of not drilling an expensive injector well.

The 40 directional wells of the second drilling campaign following the fault planes were successful because they crossed still original volumes, but not as successful as those of the first campaign (vertical wells) that crossed much larger volumes than those during the second one.

Over time the recent drilled directional wells has shown results much lower than expected due to smaller reservoirs volumes found. The reason is that they crossed small reservoirs and often with some depletion degree (more proximity of the oil/water and oil/gas contact) with increasingly difficulties to maintain a minimum distance from the fault and water/oil contact.

5. Conclusions

The accentuated field production decline is due to a combination of field intrinsic factors with conjuncture factors: long production history, unfavorable conjuncture of rig costs and product sell prices, extremely adverse geological aspects (reservoirs at great depths, the majority of the reservoirs are small, high water saturation reservoirs, a diversity of reservoirs with different pressures and fluid contacts.

The lateral jetting would be a workover low cost alternative for having been nationalized allowing to make small accumulations with low RF economically viable. This technique would take advantage of two favorable field conditions: great amount of stacked reservoirs and high level of rock reservoir compaction preventing the collapse of the jetted legs.

A new criterion is proposed for well location that is supported in a new 3D seismic acquisition, with specific parameterization, aiming areas with little information and to improve the resolution of near areas. This would enable the economical drilling of new wells because it would be increased the likelihood of crossing original and larger volumes.

This work may be applied to all onshore fields having the same difficulties in making economically viable hydrocarbon volumes considered small.

6. Nomenclature

RF = Recovery Factor
GI = Cumulative injected gas volume
Gp = Cumulative produced gas volume
NGL= Natural Gas Liquid
Np = Cumulative produced oil volume
P&D = Pesquisa e Desenvolvimento
TCP = Tubing conveyd perforating tools
OOIP = Original Oil in Place
OGIP = Original Gas in Place
Wp = Cumulative produced water volume
WI = Cumulative injected water volume

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