# ECONOMICAL ANALYSIS OF PETROLEUM FIELDS UNDER SOLUTION GAS DRIVE

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***Abstract.*** *Solution-gas-drive reservoirs under primary depletion present low recovery factor, usually less than 20%. Large decline in flow rate of the well and in reservoir pressure occur due to fast natural reservoir energy depletion. Anti-economic scenerios are soon reached by these production conditions and premature field abandonment can occur. Despite these conditions, anomalous high recovery and improved production rates associated with pressure maintenance have been observed in some heavy oil field and these results have input a renewed interest on solution gas drive mechanisms and related aspects of production. This work aims to contribute with understanding of affecting factors on production development strategy for solution gas drive reservoirs. Combining a simplified reservoir configuration, an analytical forecast model and an economic methodology based on Brazilian laws, productive and economic results were analyzed for different geological (reserve size, gas cap), operational (flowing well pressure) and economic (oil price and production costs) conditions. Results of average reservoir pressure, GOR, oil and gas flow rates, cummulative production volumes profile and net present values associated to production and development field strategy were evaluated in an integrated way and compared with the literature observations for this subject.*

***Keywords****: solution gas drive; production forecast; economic analyses, net present value.*

## 1. Introduction

When oil is produced, reservoir pressure drops, reservoir fluids expand and pore volume reduces, causing more production and pressure drop, which drives more oil. The process is continuous and since formation and oil compressibility are low, reservoir pressure drops fast and saturated conditions are observed before 5% of original oil volume in place is recovered. At this point, solution gas drive mechanism starts to run. Below saturation conditions, pressure drop causes vaporization of lighter oil fractions and since gas is more expansible than liquid, the expanded oil is driven out of the reservoir. The process is perfect while gas remains dissolved in the liquid phase, however when critical saturation of gas is reached, a continuous gas phase is formed and gas flow rises at the same time oil flow reduces. Increasing of gas-oil ratio (GOR) occurs because the high gas mobility related to oil phase, but when the gas is produced the reservoir energy is used (Thomas *et al*., 2001). Despite these conditions, anomalous high recovery and improved production rates and pressure maintenance have been observed in some heavy oil field. This unusual high primary performance has been attributed to sand production, foamy oil behavior and matrix deformation, since heavy oil generally is associated with high porosity and permeable formations. These results have input a renewed interest on solution gas drive mechanisms and related aspects of production. Albartamani *et al.* (1999) studied gas releasing stages. Akin& Kovscek (2002) developed an experimental apparatus to observe solution gas drive phenomena in pore-scale at a variable of pressure and temperature; they could observe pore-scale flow events, such as liquid-lens breathing, bubble coalescence and bubble snap-off. Bayon *et al.* (2002) run two numerical models, using CMG STARS as a platform, partitioning the gas into different groups (solution gas, dispersed gas, and free gas) in order to define the mobility of the gas, and consequently gas relative permeability. They compared numerical results against two long core depletion experiments, conducted at significantly different depletion rates. Depletion rate was also focused by Urgelli *et al.* (1999); Maini (2003); Tang *et al.* (2003) and Tang *et al.* (2004). In 2003, Tang *et al.* focused effects of composition running depletion tests with two different heavy crude oil and two mineral viscous oils; and in 2004 Tang *et al.* investigated overburden pressure effects on heavy oil solution gas drive. Intending to provide data to reservoir simulation studies, Satik *et al.* (2004) developed a systematic investigation of rock, fluids and depletion tests related to Hamaca Field in Venezuela where heavy oil has been produced under solution gas drive. Tang and Firoozabadi (2005) studied the effects of GOR, temperature and initial water saturation in heavy oil under solution gas depletion. Researchers have pointed out higher oil recovery related to higher depletion rate. Also, it has been observed reduction on gas mobility associated with fast depletion.

This work aims to contribute with understanding of intervenient factors related to the production development strategies for solution gas drive reservoirs. Combining a simplified reservoir configuration, an analytical forecast model and an economic methodology based on Brazilian laws, productive and economic results were analyzed under different geological (reserve size, gas cap), operational (flowing well pressure) and economic (oil price and production costs) conditions. Results of average reservoir pressure, RGO, oil and gas flow rates, cumulative production volumes profile and net present values associated to production and development field strategy were evaluated in an integrated way and compared with the literature observations for this subject.

## 2. Models

### 2.1. Reservoir and Forecast Model Description

Cylindrical geometry was used to represent a simplified reservoir model and a material balance method was applied to evaluate oil production performance. Reservoir frontiers were assuming closed, without water influx and any enhanced recovery process contributions. Following main calculations are present. Input variable definitions can be seen at the Tables 1 and 2

Applying volumetric estimation, initial oil volume in place (*N*) was calculated as:

$$N = \frac{1}{5{,}615} \frac{V_{po} * So_i}{Bo_i} \tag{1}$$

where $V_p = \pi \cdot \phi \cdot \left(r_e^2 - r_w^2\right) \cdot h$ , $S_{oi} = 1 - S_{wi}$ and the factor (1/5,615) converts volume from [ft$^3$] to [bbl].

If considering a gas cap presence into the reservoir, the free gas initial volume (*G*) was estimated as function of the ratio of initial free gas to initial oil volume (*m*), as follows:

$$G = 5{,}615 \cdot N \cdot m \frac{Bo_i}{Bg_i} \tag{2}$$

Flow rate ($Q_o$) were calculated considering semi-steady-state flow condition:

$$Q_o = \left(\frac{1}{141{,}2}\right) \frac{k \cdot h}{B_o} \frac{k_{ro}}{\mu_o} \left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4}\right] \left(p_R - p_{wf}\right) \tag{3}$$

where factor (1/141,2) adjusts units and $p_R$ represents average reservoir pressure.

Average reservoir pressure, as a time function, is given as reservoir pressure discounted for depletion rate applied, as follows:

$$p_{R,new} = p_{R,old} - \Delta p \tag{4}$$

Oil saturation ($S_o$) as function of average reservoir pressure is calculated applying Muskat Equation (Rosa & Carvalho, 2002), that is reproduced bellow:

$$\frac{dSo}{dp} = \frac{So * \lambda + (1 - So - Swi) * \xi + So * \eta * \psi + m(1 - Swi) * \xi}{1 + \left(\frac{\mu o}{\mu g}\right) * \psi} \tag{5}$$

where

$$\eta = \frac{1}{Bo} * \left(\frac{\mu o}{\mu g}\right) * \frac{dBo}{dp}; \qquad \alpha = \left(\frac{Bo}{Bg}\right) * \left(\frac{\mu o}{\mu g}\right); \qquad \lambda = \left(\frac{Bg}{Bo}\right) * \frac{dRs}{dp}; \qquad \psi = \frac{kg}{ko};$$
$$\xi = Bg * \frac{d}{dp}\left(\frac{1}{Bg}\right); \qquad RGO = \left(\frac{kg}{ko}\right) * \left(\frac{\mu o}{\mu g}\right) * \left(\frac{Bo}{Bg}\right) + Rs; \tag{6}$$

### 2.2. Economic Model Description

Economic analyses are based on net present value (NPV) attached to petroleum reservoir. The model was previously presented by Moreno and Schiozer (2002) and is applied to studied cases focused here.

Net present value is expressed by:

$$NPV(t) = -Invest(t) + \int_0^{t_n} \frac{CF(t)}{(1+rate)^t} d(t) \tag{7}$$

where *Invest (t)* is exploration investments (equation 8), *CF(t)* is cash flow (equation 9), *rate* is discount rate and *t* is time.

Exploration investments *Invest(t)*, includes Capital Expenditures $CapEx(t_0)$, abandonment expenses $k_{ab}$ $CapEx(t_0)$, both computed at initial of development time, and periodic expenditures $C_{per}(t_{per})$ taken into account at initial time of a unit operation. In this paper periodic expenditures is restricted to drilling cost ($c_{drill}$) since only one well is considered drill at the initial of development time.

$$Invest(t) = CapEx(t_0) - k_{ab} \cdot CapEx(t_0) + \sum_{k=1}^{p} C_{per}(t_{per}) \tag{8}$$

Cash flow CF(t), equation (9), includes oil and gas production costs (cop and cgp) and net revenue due to oil and gas commercialization after application of Brazilian Federal income taxes (IRCS, rPC), royalties tax (rR) and special government take (rPE, Equation 10). Any other periodic expenditure was included.

$$\begin{aligned} CF(t) = &-\left[c_{op} \cdot Q_o(t) + c_{gp} \cdot Q_g(t)\right] + \\ &+ (1 - IRCS) \cdot \left[1 - r_R - r_{pc} - r_{PE}(t)\right] \cdot \left[p_o \cdot Q_o(t) + p_g \cdot Q_g(t)\right] \end{aligned} \tag{9}$$

The special income tax ($r_{PE}$), expressed bellow, is applied when the cumulative field production during three months overcome the imposed limit ($Q_{trib}$) of the National Agency.

$$r_{PE}(t) = -0{,}2(1 - r_R) \frac{\left[c_{op} \cdot \int_{t_0}^{t_{tri}} Q_o(t)dt\right]^2 - Q_{trib}}{\left[c_{op} \cdot \int_{t_0}^{t_{tri}} Q_o(t)dt\right]^2} \tag{10}$$

Payout Time PT as pointed bellow gives additional economical indicator. Payout time represents the time needed to recover the investments.

$$NPV(PT) = 0 \qquad \text{or} \qquad Invest(t) = \int_0^{PT} \frac{CF(t)}{(1+rate)^t} d(t) \tag{11}$$

## 3. Studied Cases

In order to contribute with understanding of some intervenient factors related to a production development strategy for solution gas drive reservoirs, nine different cases were evaluated and compared. First of all, a basic case was run, which input data are present in the Item 3.1. Then eight cases: a) including an adjacent gas cap to oil zone; b) changing bottom hole pressure, c) changing initial oil volume and finally d) changing oil price were run and their results were compared with basic case results. These variations of basic case are summary presented in Table 3. Output data and discussions are reported in the Section 3.2.

### 3.1. Input Data

In this section are present fluids-rock properties, economic data and operational conditions and constraints.

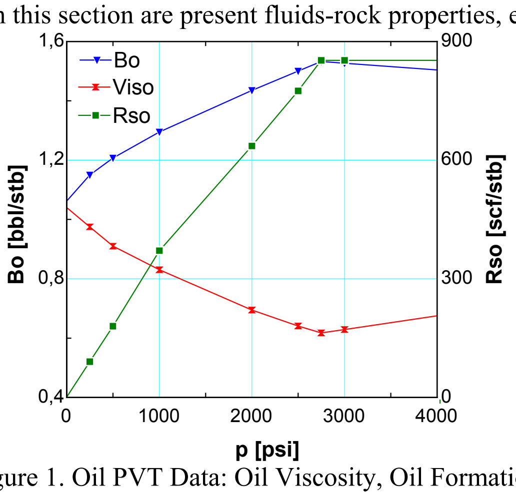



Figure 1. Oil PVT Data: Oil Viscosity, Oil Formation Volume Factor, solution gas-oil ratio

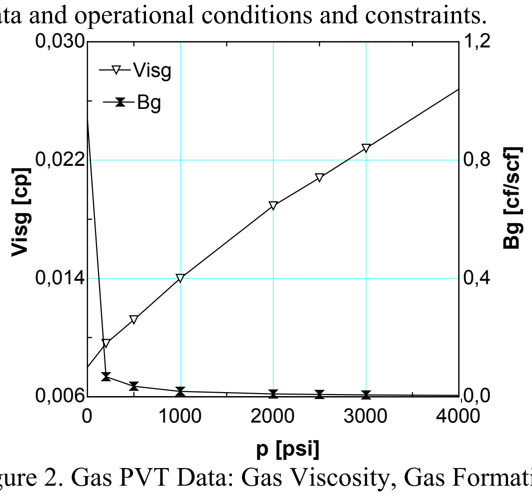



Figure 2. Gas PVT Data: Gas Viscosity, Gas Formation Volume Factor

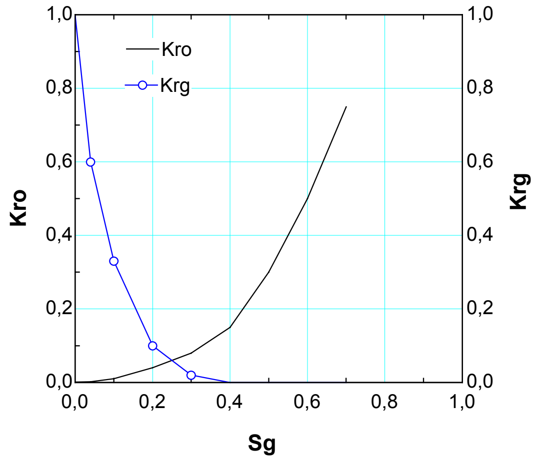


Figure 3. Relative Permeability Data

Table 1. Reservoir Data and Operational constraints.

| | | | |
|---|---|---|---|
| Initial water saturation | $S_{wi}$ | [fraction] | 0.20 |
| Reservoir initial pressure | $p_i$ | [psi] | 2750. |
| Rock compressibility | $c_R$ | [1/psi] | 5.D-6 |
| Ratio of initial free gas to initial oil volume | $m$ | [fraction] | 0.0 |
| Bottom hole pressure | $pwf$ | [psi] | 500. |
| Initial porosity | $\Phi ini$ | [fraction] | 0.20 |
| Saturation pressure | $p_{REF}$ | [psi] | 2750. |
| Well diameter | $d_w$ | [ft] | 1.0 |
| Reservoir diameter | $d_e$ | [ft] | 10000. |
| Reservoir Thickness | $h$ | [ft] | 200. |
| Absolute permeability | $k$ | [mD] | 50. |
| Abandonment pressure | $p_{AB}$ | [psi] | 50. |
| Abandonment oil rate | $q_{AB}$ | [stb/day] | 50 |

Table 2. Economic Data.

| | | | |
|---|---|---|---|
| Discount rate | *rate* | % (year) | 15 |
| Capital Expenditures | *CapEx* $(t_0)$ | MM US$ | 50 |
| Government Take | *IRCS* | % | 33 |
| Abandonment coefficient | $k_{ab}$ | % | 0,5 |
| Royalties tax | $r_R$ | % | 10% |
| Income tax | $r_{PC}$ | % | 3,65 |
| Gas production cost | $c_{gp}$ | US$/m$^3$ | 0,03 |
| Oil production cost | $c_{op}$ | US$/m$^3$ | 37 |
| Drilling cost | $c_{drill}^{(*)}$ | US$ | 1.500.000 |
| Oil price | $p_o$ | US$/bbl | 20,00 |
| Production field limit | $Q_{trib}^{(*)}$ | m$^3$ de EO (3 months) | 2.700.000 |

Table 3. Variations from Basic Case

| | | | | |
|---|---|---|---|---|
| 1 | Influence of the Gas Cap Size * | $m$ | [fraction] | 1.0 |
| | | $h$ | [ft] | 400. |
| 2 | | $m$ | [fração] | 0.5 |
| | | $H$ | [ft] | 300. |
| 3 | Influence of Depletion Rate | $pwf$ | [psi] | 1500. |
| 4 | | $pwf$ | [psi] | 50. |
| 5 | Influence of Original Oil in Place | $d_e$ | [ft] | 15000. |
| 6 | | $d_e$ | [ft] | 5000. |
| 7 | Influence of Oil Price | $p_o$ | US$ /bbl | 25,00 |
| 8 | | $p_o$ | US$ /bbl | 15,00 |

(*) The parameter $h$ were changed relate to basic case in order to maintain same original reservoir oil.

### 2.3. Output data and Discussion

Results of average reservoir pressure ($p_R$), gas-oil-ratio (*GOR*), oil and gas rates ($Q_o$ and $Q_g$), cumulative production volumes history (*Np* and G*p*) and net present values (*NPV*) associated to production strategy are presented for studied cases. Since no mobile water is present in the reservoir, no water is produced, and produced gas comes from dissolved gas from oil zone. No gas production from gas cap zone was considered. It is relevant to observe that four different abandonment criteria were taking into account, which are: abandonment pressure, abandonment rate, abandonment time, specified as about 35 years, and abandonment NPV or maximum NPV attached to the development strategy. However, showed results were not limited by NPV performance. Abandonment condition of each studied case is presented in the Table 4.

**a) Influence of the Gas Cap Size**

It is well known that an adjacent gas cap to oil zone is an important maintaining factor of reservoir pressure, mainly if no free gas from cap is produced. Considering this hypotheses and analyzing the influence of gas cap size, three different cases results are presented in Figure 4: a) basic case, b) gas cap size equivalent to half oil zone size (m=0,5) and c) gas cap size equivalent to oil zone size (m=1,0). Depletion reservoir performance was quite similar for three studied cases, since no free gas of the cap was considered being produced (Figure 4a). However, rising on oil rate and mainly on gas rate were caused by that minimum differences on average reservoir pressure (Figures 4b). At Figure 4c, we can observe higher GOR level directed related to gas cap size and since gas production jeopardizes oil production (lower recovery), economic value of the project is proportionally lower too (see maximum NPV at the Figure 4d). As we expected, in the case with an additional natural maintaining factor of reservoir pressure given by gas cap presence, even producing with quite similar depletion rate, higher oil rate remains during a much long period compared with isolated reservoir, then payout time occurs sooner and maximum expected NPV are higher.

**b) Influence of Depletion Rate**

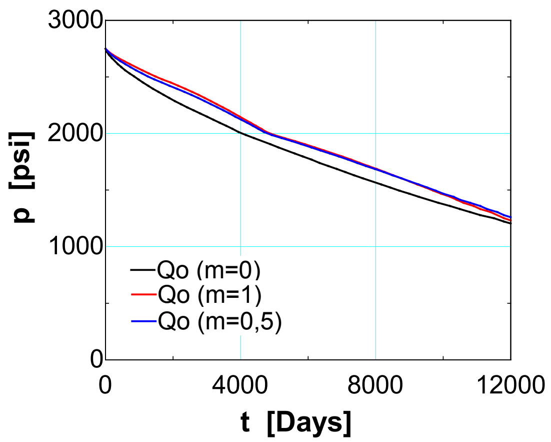
Production rates are the response to difference between reservoir pressure and bottom hole pressure. When different bottom hole pressure condition is applied to a drainage reservoir area, gas critical saturations can be reached slowly (BHP=1500 psi) or rapdly (BHP=50 psi). This consequence can be observed in the Figure 5. Depletion rate is inversely proportional to BHP while gas production rate and GOR shows rising values directly related to depletion performance. Payout time of the development strategy is directly proportional to depletion condition too, for lower BHP, sooner positive NPV is reached (see Figure 5d and cases 3, B and 4 in the Table 4). This condition is result of higher oil rate due to higher depletion rate given by low BHP. It is important point out that for too much low depletion rate, reaching final recovery could take hundred of years, which is not technically acceptable.

**c) Influence of Original Oil in Place**

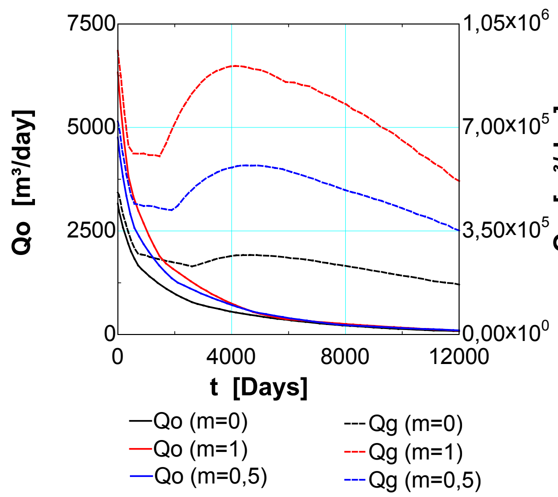
Reserve size is a very important factor for an economic point of view. Depending upon the original oil in place, economical viability cannot be observed (see Figure 6d and case 6 in Table 4). Necessary expenditures to field development can be incompatible with maximum expected NPV. Contrary, reservoir with big size shows high NPV due to high cumulative production (see case 5 in Table 4). In this case optimum condition can not even be reached in a reasonable development exploitation time and rising drainage rate would be positive. In fact, an optimized development strategy can be reached combining reservoir size with operational conditions to special field characteristics.

**d) Influence of Oil Price**

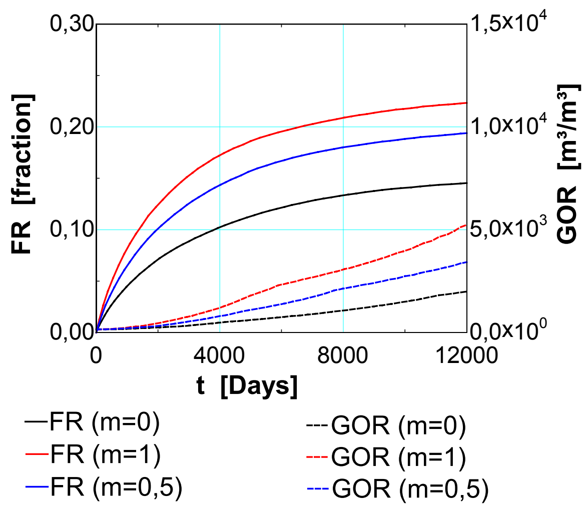
Oil price is a decisive factor in economic and abandonment development strategy analysis (see Figure 7). Depending on price, production strategy can not be economically viable (case 8 in Table 4) or it can be related to shorter payout time and higher abandonment time (case 7 in Table 4) when compared to lower oil price condition (basic case). Favorable price condition permits extend production time to reach new maximum NPV related to previous development strategy.



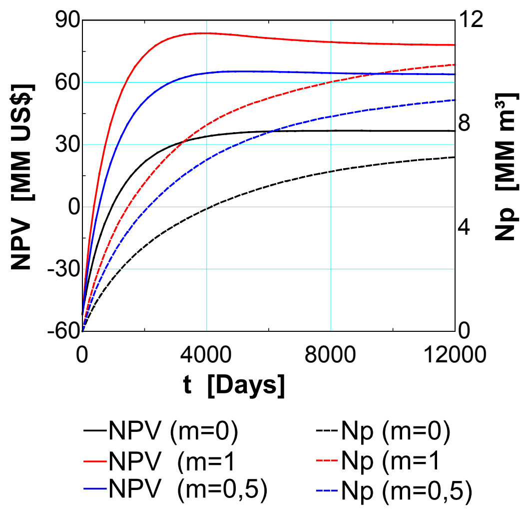

(a) BHP *versus* Time




(b) $Q_o$ and $Q_g$ *versus* Time




(c) FR and GOR *versus* Time

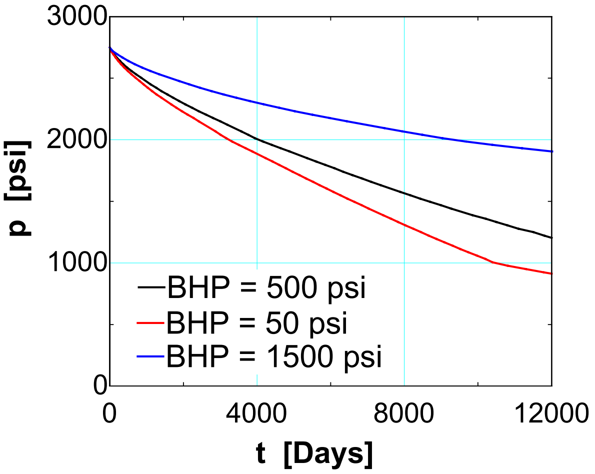



(d) NPV and Np *versus* Time

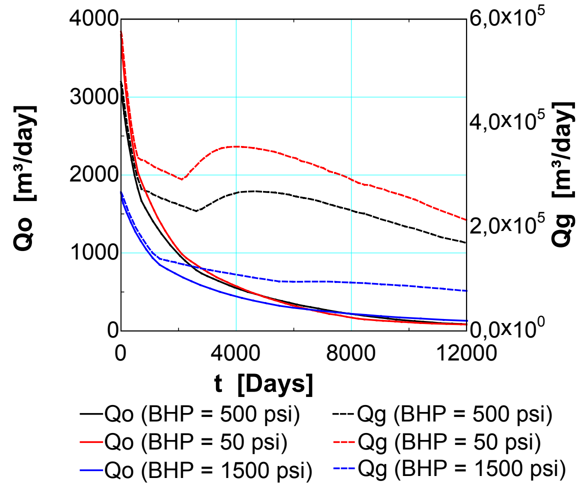
Figure 4. Economic and production results to reservoir without gas cap (basic case) and with gas cap (m=1 and m=0,5)

Table 4. Abandonment Condition Data for Studied Cases.

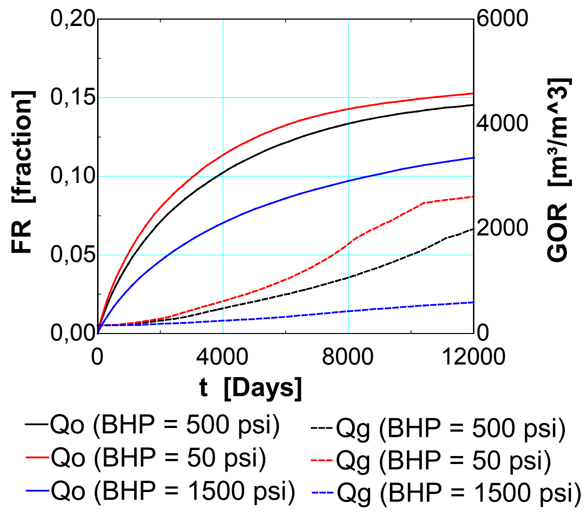
| | $PT_{AB}$ [Days] | $P_{AB}$ [psi] | $Time_{AB}$ [Days] | $Qo_{AB}$ [stb/D] | FR [%] | po [US$/bbl] | RGO [$m^3/m^3$] | Qg [$m^3$/dia] | Qo [$m^3$/dia] | Np [MM $m^3$std] | Gp [MM $m^3$std] | NPV [MM US$] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **B** | **912** | **1468** | **8986** | **1071** | **14** | **20** | **1267** | **215521** | **170** | **6,4** | **2327** | **38,9** |
| **1** | 298 | 2123 | 4129 | 4466 | 17 | 20 | 1278 | 907940 | 711 | 8,1 | 3116 | 83,6 |
| **2** | 365 | 1959 | 5224 | 3074 | 16 | 20 | 1164 | 567991 | 488 | 7,3 | 2655 | 65,3 |
| **3** | 2303 | 1905 | 12015 | 815 | 11 | 20 | 596 | 77237 | 130 | 5,2 | 1313 | 12,5 |
| **4** | 751 | 1468 | 6838 | 1569 | 14 | 20 | 1267 | 316231 | 250 | 6,4 | 2326 | 46,8 |
| **5** | 749 | 1877 | 12068 | 2557 | 11 | 20 | 626 | 254922 | 407 | 11,9 | 3108 | 78,7 |
| **6** | - | 623 | 8262 | 57 | 16 | 20 | 3381 | 30476 | 9 | 1,9 | 1178 | -19,8 |
| **7** | 417 | 1277 | 11118 | 625 | 14 | 25 | 1815 | 180346 | 99 | 6,6 | 2745 | 95,9 |
| **8** | - | 1196 | 12139 | 523 | 15 | 15 | 2011 | 167188 | 83 | 6,7 | 2920 | -18,2 |



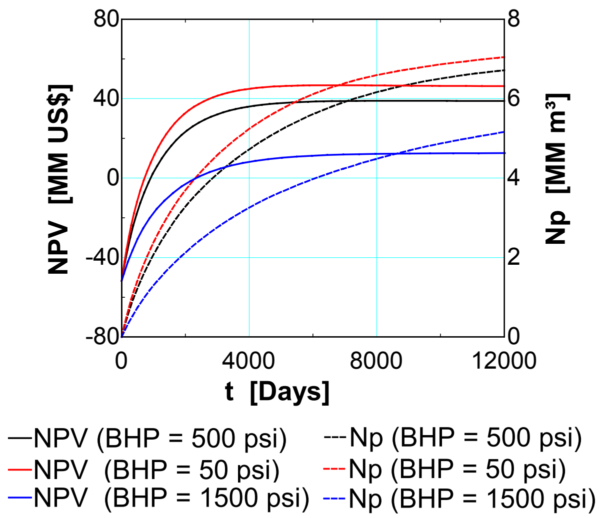

(a) BHP *versus* Time




(b) $Q_o$ and $Q_g$ *versus* Time

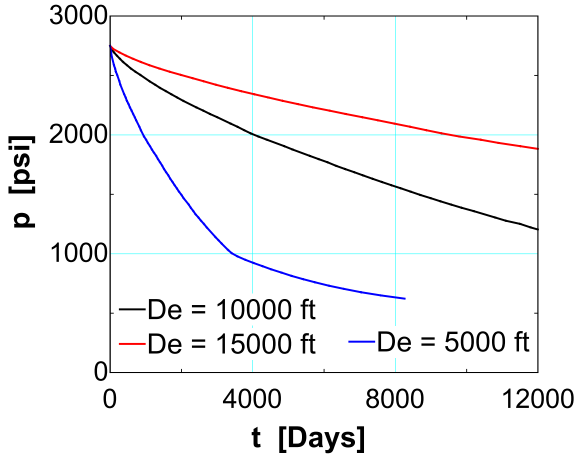



(c) FR and GOR *versus* Time

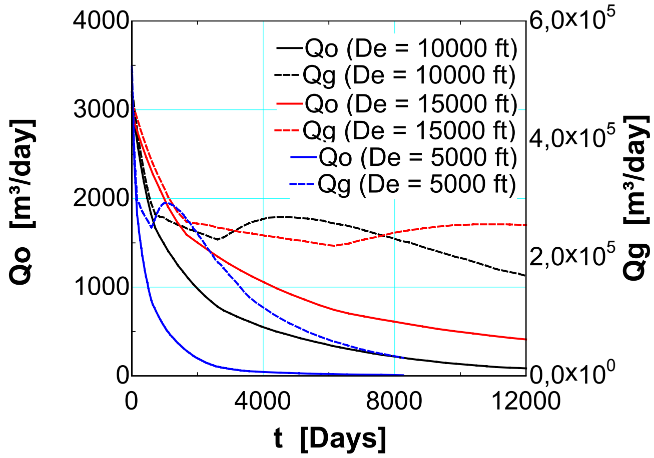



(d) NPV and Np *versus* Time

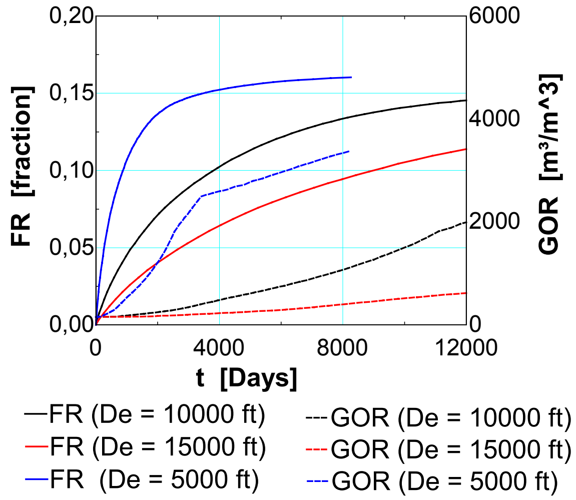
Figure 5. Economic and prodution results to BHP=500 psi (basic case), BHP=1500 psi and BHP=50psi



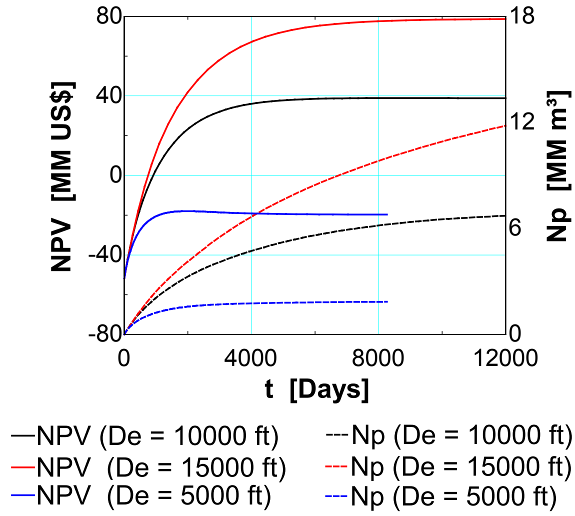

(a) BHP *versus* Time




(b) $Q_o$ and $Q_g$ *versus* Time




(c) FR and GOR *versus* Time




(d) NPV and Np *versus* Time

Figure 6. Economic and production results to OOIP=292 MM STB (basic case), OOIP =657 MM STB and OOIP =73 MM STB

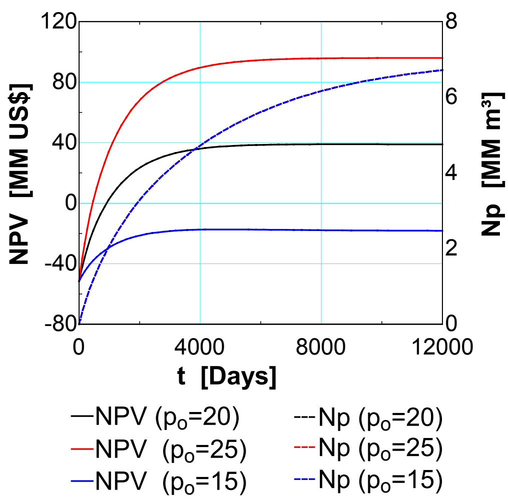



Figure 7. Economic results to basic case considering oil price of US$ 20/bbl, US$ 25/bbl and US$ 15/bbl

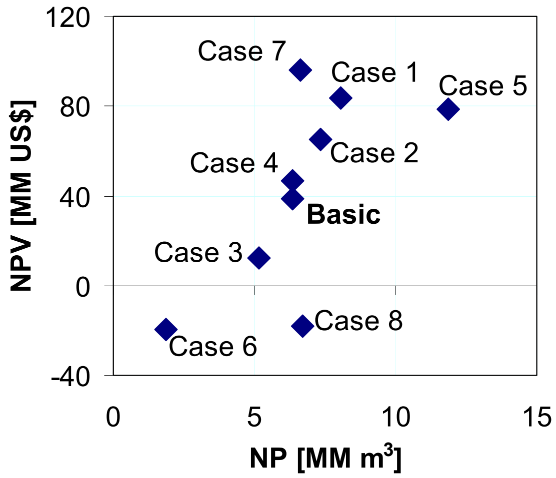



Figure 8. Economic and production results to abandonment conditions for the studied cases

## 3. Conclusions

An integrated study combining reservoir characteristics, operational, economic conditions and abandonment constraints were developed. Ultimate goal is contribute with solution gas drive mechanism understanding under viable development strategy of production and the main conclusions to be drawn from this study are the following:

Presence of gas cap without gas cap production helps on average reservoir pressure maintenance and consequently more oil is produced in a fast way (higher oil rate) compared to the case without gas cap. These effects are directly proportional to gas cap size (see cases B, 1 and 2).

Payout time related with a development strategy is directly proportional to depletion condition; as lower is BHP sooner positive NPV is reached (cases 3, B and 4). This condition is related to higher oil rate due to higher depletion given by low BHP.

Economical viability cannot be obtained if original oil volume or oil price are low (cases 6 and 8, respectively).

Reservoir with big size shows high NPV due to high cumulative production (see case 5), but optimum production and economic performance cannot be reached depending upon applied development strategy.

Favorable price condition permits extend production time to reach new maximum NPV related to previous development strategy.

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## 5. Responsibility notice