Optimizing Oil Production for the Intermittent Gas Lift Method

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Abstract. *The Intermittent Gas Lift, IGL, is an artificial lift method employed to develop partially depleted and low productivity reservoirs that haven't enough internal pressure to lift oil up to the surface. It is feasible if the plant has available a high pressure gas supply at a low cost. The IGL method consists of a injection of a volume of gas at the bottom of the production pipe by a gas-lift valve. As the gas expands it lifts an amount of oil to the surface. The IGL cycle has three main stages: the oil filling up of the well vertical column; the gas injection and the output of oil at surface. The cycle period is a key parameter to control the daily oil production. The estimates of the cycle period are based on the well IPR curves which, very often, are not accurate for mature reservoirs. This work presents an alternative method to optimize the cycle productivity by measuring the residence time of the liquid slug at the surface. The measurement technique is based on the application of capacitive transducers.*

Keywords: *Intermittent Gas Lift, capacitive transducers, slug flow*

1. INTRODUCTION

The Intermittent Gas Lift, IGL, is an artificial lift method employed to develop partially depleted and low productivity reservoirs that haven't enough internal pressure to lift oil up to the surface, Carvalho (2004). It is feasible if the plant has available a high pressure gas supply at a low cost. This is the typical scenario of the oil reservoirs found in Bahia and Rio Grande do Norte states where nearly 30% of the wells produce by means of pneumatic artificial lift methods. Most of the fields in these states are developed by Petrobras. A production field collects oil from 30 to 100 wells which are grouped in clusters arrayed in a parallel configuration as schematically represented in Fig. 1. The cluster production is colleted into a manifold, directed to the gas-oil separator and then to an oil collecting tank. The gas looping is a closed circuit. The high pressure gas is supplied by the compressors station, injected on the wells and recovered at the gas-oil separator and re-directed to the compressor station. The gas injection and the oil production of the whole field is continuously monitored by a supervisory system. Each well has a programmable logic controller, PLC, which has two functions: to feed the supervisory system with the well log and to control the cyclic gas injection for lifting the static oil column. The PLC controls the time of aperture of the gas injection valve but the supervisory system acts on the well network setting the period of cycle for each well. This supervisory system is fully detailed in Corrêa (1998) and Corrêa et. Al (2001) and it is working with success for more than a decade at the Petrobras operations at the states of BA and RN. By monitoring the well log the system readily detect malfunctioning components reducing the period of the well non-productivity. Also the high pressure gas resources are used without waste by controlling the gas injection time. Despite of the successful operation the supervisory system has a weak point: it is not capable to maximize the well production by optimizing the cycle period at the current well characteristics. The best cycle period is previously estimated for each well during well design stage based on the Reservoir Index of Productivity, RIP. Unfortunately the RIP is very often an uncertain variable and it also changes with time and by the occurrence of water and free gas in the oil stream. These factors introduce uncertainties on the optimum cycle period to render the a maximum well productivity either by lack of reliable RPI information or due to well aging.

The management and optimization of the IGL are based on the development of mechanistic models such as: Neely et al. (1973), Brown (1980), Liao et al. (1995), Carvalho (2004) among others. Despite of the efforts to develop the mechanistic models there are uncertainties associated with the liquid properties, well aging and also models limitations which shadow the optimization process. This kind of problem becomes paramount when one is dealing with an array over 300 producing wells, typical of the producing fields at BA and RN states. This work proposes to access experimentally the optimum cycle period by measuring the surface residence time of the produced oil slug based on intrusive capacitive sensors. The structure of the article is as follow. A brief description of the IGL production cycle is in section two. Section three describes the experimental facility and the residence time measurement technique. The experimental results are in section four and the optimizing method is in section five. Section six closes the article with the conclusions.

2. THE IGL PRODUCTION CYCLE

This section briefly describes the IGI production cycle in a typical well. A schematic well representation is in Fig. 2 with the used nomenclature to support the cycle description. The IGI cycle can be described in five stages accordingly to Carvalho and Bordalo (2005). i) pressurizing the well casing by opening the gas injection valve; ii) oil lifting when the well casing pressure reaches the aperture set point of the operating valve at the bottom of the tube; iii) the oil production reaches the well head; iv) depressurization of the well tube while the oil production rushes to the gas-oil separator; v) oil tube filling feed by the existing pressure difference between the reservoir and the tube.

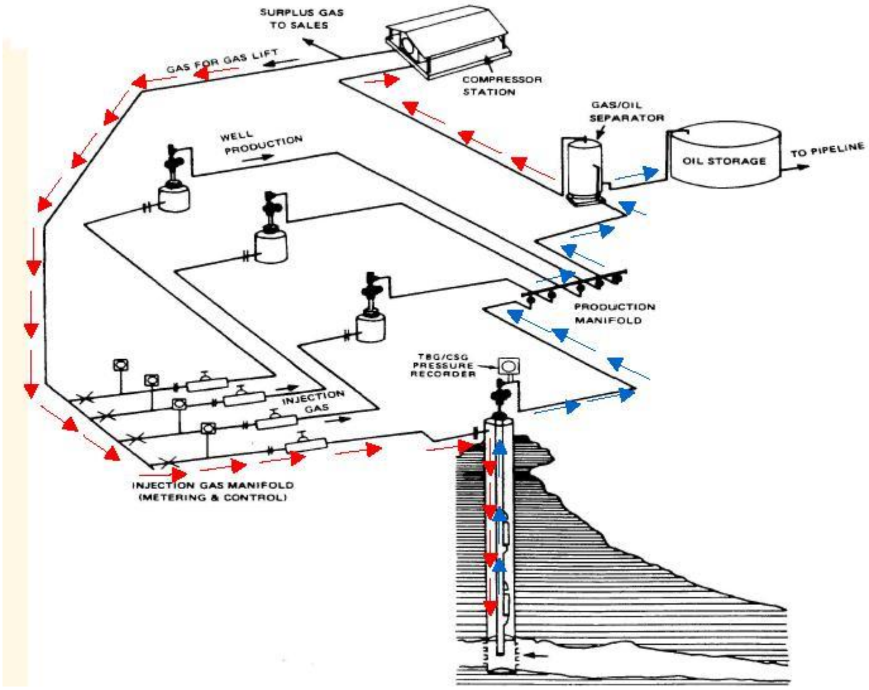

Figure 1 Distribution and collecting network for the gas supply and the crude oil.

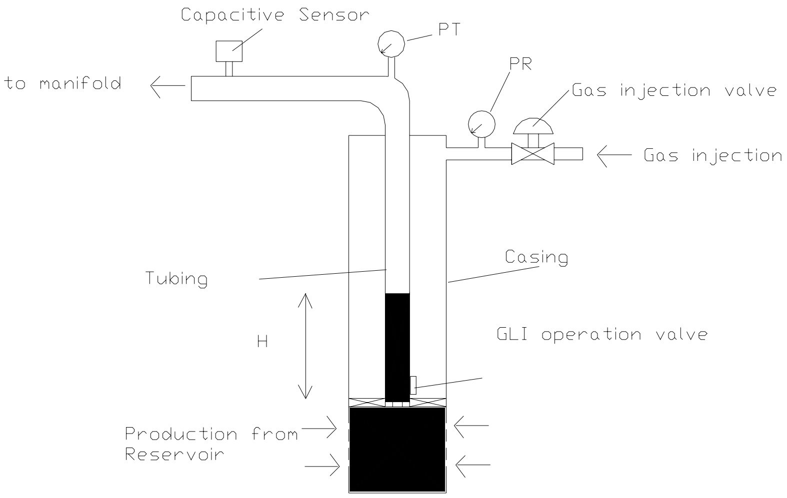

Figure 2 - Well schematic representation and nomenclature

Currently the production cycle is monitored by registering the time history of the pressure measured at the casing and surface tube, PR and PT. Typical PR and PT curves during a cycle period is in Fig. 3. The stages (i) and (ii) are represented by the segments A-B and B-C on the PR curve. The A-B segment represents the casing pressurization and the B-C segment, with a slower slope, happens after the operating valve aperture. The gas injection valve and operating valve have the aperture and shut down instants represented by points (A), (B) and (C), (D) respectively. The time interval between points (A) and (C) is the gas injection time or Tinj. Also, the time interval between points (B) and (D) is the aperture time of the operating valve or Tav. After the gas injection valve is shut down, point (C), the casing pressure falls and return to its initial value, point (D). A cycle period is completed when the gas injection valve is open again, point (A); the cycle period is represented by T. The register of the tube pressure, PT, is delayed from the events on the PR curve. The delay is due to the time of travel of the oil slug to reach the surface. When the lifted oil slug reaches the tube transducer the pressure register rises. The fall of the PT correspond to the end of the slug. The time of travel, Tvg, is represented by the instant when the operating valve opens the oil slug lift off (point B on PR curve) and the instant when the tube pressure rises or the liquid slug reaches the surface (point B on PT curve).

During the production cycle the ratio between gas injection time and the time of travel is controlled by the PLC to stay $0.9 < Tinj/Tvg < 1.1$, Corrêa (1998). Keeping this time ratio within this range suffices to produce the oil to the surface without wasting the compressed gas supply. The operating valve aperture time, Tav, is not controlled directly by the process. The aperture of the operating gas lift valve depends on the casing pressure, on the gas lift bellows pressure and on the oil head H at the tube in such way that the highest is H the lower will be necessary casing pressure to open the operating valve. The malfunctioning of the gas injection valve, operating valve and high pressure gas supply failure are detected from the PR and PT curves by recognition pattern software.

The cycle period is composed by two time intervals. The first corresponds to the gas injection time, Tinj, and the second is the accumulation time interval, Tac, corresponding when the reservoir feeds to the well tube increasing the height of oil column H. The growth rate of H is similar to the one found in a first order system, see Eq.(6). H grows with Tac approaching assymptoticaly the maximum height, which is equal to the reservoir static head. The averaged oil production per cycle is a trade off between the cycle period and the height of the oil column. The greater the column height the greater will be the produced oil volume but the larger will be the cycle period. The optimum cycle period is a pre-set variable built in the supervisory program based on the estimates of the well RPI. This set point may not represent the maximum production because it is based on the RPI which some times is not measured but estimated and also the RPI changes due to reservoir aging, presence of free gas and water. This article objective is to propose an experimental technique to access the optimum cycle period to render the maximum oil production.

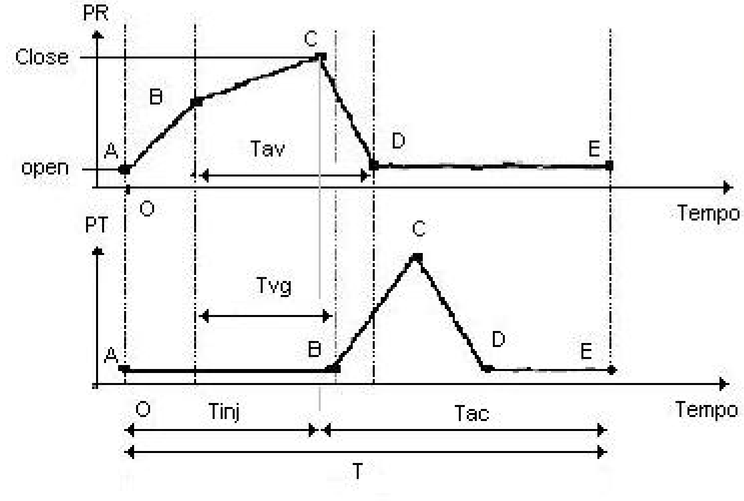

Figure 3 - Typical pressure time history at the well casing and at the surface tube, PR and PT.

3. THE EXPERIMENTAL METHOD

The liquid lifting process due to the gas expansion is reproduced in a small size experimental setup described in this section. The main objective of this set up is to reproduce qualitatively the main characteristics of the liquid lifting process. In fact it is not possible to scale laboratory phenomena with an actual well producing line. The main dimensions between the model and prototype are two to three orders of magnitude distinct; similarly the pressure, the displaced volumes and the time scales are offset by the same orders of magnitude. Despite of the lack of geometrical, kinematical and dynamical similarity, it is possible to draw some qualitative information regarding to the behavior of the liquid slug lifting process.

The experimental set up consists of a vertical tube 9m long followed by a horizontal tube 27m long both with 26mm ID. The tubes are of transparent Plexiglas to allow visual observation of the liquid slug flow. Compressed air is used as the gas component while water represents the liquid component. The use of water instead of oil is justified based on the fact that mature reservoirs usually have water content 85% or higher in volume. The supervisory system controls the set of solenoid valves, pressure and level transducers and liquid pumps allowing a fully automatic operation. Each test has a sequence of operations. The first stage is to set a static water level H inside the vertical tube which may range from 3m to 7m in height. The water column height is equivalent to the produced oil volume from the reservoir to the well tube during the accumulation time, Tac. The second stage sets the pressure for air injection. The compressed air supply, available at 7Barg, feeds the air tank, 6.7 liters in volume, to a pressure ranging from 1Barg to 4Barg. The air tank pressure level corresponds to the well casing pressure. The third stage is the gas injection inside the tube. It is done controlling the opening time of the solenoid valve #3 which may range from 0.5sec to 5sec. The opening time of the solenoid valve #3 represents the aperture time of the operational valve, Tav. Once the solenoid #3 is open the pressurized air is injected at the vertical tube lifting the static liquid column. A capacitive sensor SG1, located at 7m higher from the air injection site, register the residence time of the lifted liquid slug with the probe hereafter defined as TG.

A test is defined setting an initial water level the air pressure injection and the aperture time of the solenoid #3, H, P, Tav respectively. When the water column reaches the surface its the residence time, TG is registered. The experimental apparatus rests for 90 seconds to allow the water film, surrounding the gas bubble, to fall back to the bottom of the tube. The produced water volume, Vp, is determined subtracting the initial water volume from the final water volume. Notice the pipe volume and the column height are directly proportional to the pipe cross section area.

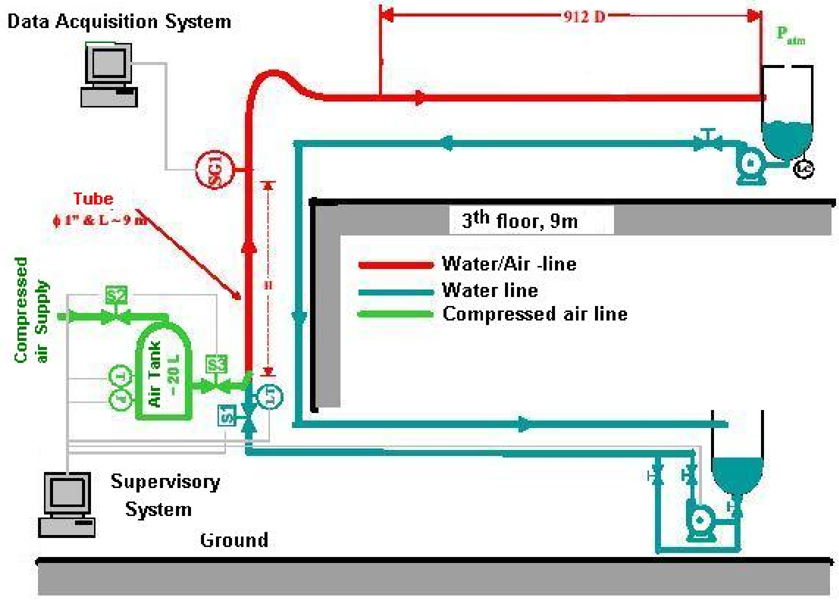

Figure 4 – Schematic representation of the IGI test section

The detection of the liquid slug residence time is measured by the sensor SG1 whose physical principle is the capacitance measurement. The major characteristic of this sensor is to use the tube as one of the capacitor plates, the second one is the cylindrical rod that crosses the pipe section, see Fig. 5. This characteristic gives the necessary robustness to the sensor to be applied in field operations meeting with the safety operational regulations concerned with mechanical strength and pressure resistance. This configuration also reduces undesired noise because the tube itself is magnetic shield and gives a natural common reference to the instrument. The occurrence of liquid or gas at the rod neighborhood is detected due to the change in the surrounding media capacitance, a fully description of the sensor is in Mastelari et alli, 2005.

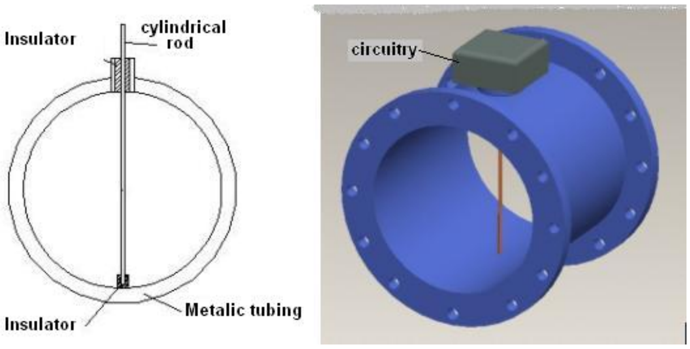

Figure 5 – Capacitive probe inside the pipe.

The capacitive sensor's electronic circuit is based on a AC Wheatstone bridge whose block diagram is represented in Fig.6. One arm of the bridge is the rod and tube impedance or the process impedance (resistive and capacitive). It is counter balanced by the impedance of the other three arms. The bridge equilibrium is set for a capacitance value of nearly 2μF which corresponds when the tube full of gas. The bridge is exited by a 100kHz oscillator with symmetric ±12VAC. The presence of the oil or water causes the bridge imbalance. It is measured by the differential operational amplifier. The signal goes through a 2kHz low pass filter and then through an amplifier. An off set voltage is added to rectified, filtered and amplified signal to give us a reference state and finally the voltage signal is converted to a standard 4 to 20mA signal.

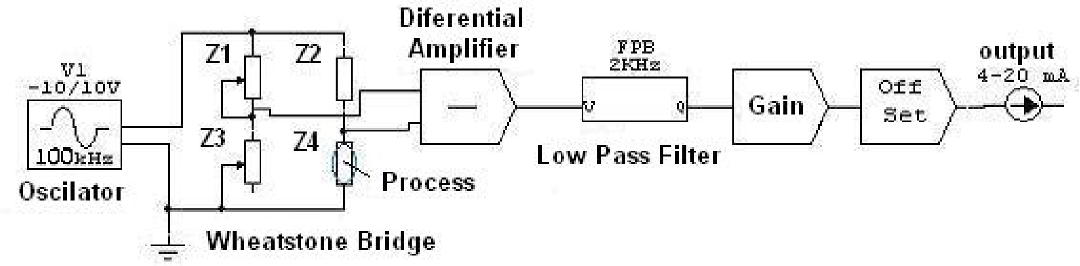

Figure 6 – Circuitry block diagram of the capacitive sensor.

4. EXPERIMENTAL RESULTS

The objective of the experimental tests was to establish a data basis of the IGL properties such as: produced water volume, Vp; liquid slug residence time, TG and the averaged liquid slug velocity, vel; as a function of the liquid static column, H; gas injection pressure, P; and time of aperture, Tav. Selected data applied to the present case is shown in Fig. 7(a)-(c), for constant time of aperture of 2sec, and three levels of gas injection pressure; the complete data base is in Rosa (2007).

Figure 7(a) shows the produced water volume, Vp, varying linearly with the static column height in such a way that the highest is the column height the greater is Vp. It is also observed that Vp is weakly dependent on the gas injection pressure. Figure 7(b) shows the produced water volume as a function of the residence time for three gas injection pressures. Keeping constant the gas injection pressure Vp always grows with TG. Also, fixing TG, Vp increases as the gas injection pressure increases. Finally in Fig. 7(c) we have the averaged liquid slug velocity as a function of the static water column height for three gas injection pressure levels. As expected, the averaged slug velocity decreases with the increases of the static column height and increases with the increase of the gas injection pressure.

The most relevant information of this data set is the fact that the residence time is proportional to the produced volume. The other data support this information and gives physical consistency to the experimental data. The dependence of Vp with Tg is not linear and it also depends on the gas pressure injection. The data, taken from the scaled down model, does not allow extrapolation to oil field data. Nonetheless it will give us qualitative information on how Vp depends on TG that will be used in the next section.

5. PROPOSITION OF THE OPTIMIZING METHOD

The averaged volumetric flow rate, Q, occurring during a cycle is simple defined by the ratio between the produced volume and the cycle period. But, the cycle period is defined as the sum of the gas injection time and the accumulation time therefore the averaged flow rate depends on three parameters: Vp, Tinj and Tac, as indicated by Eq.(1) :

$$\bar{Q} = Vp/T \equiv Vp\Big/\left(T_{inj} + T_{ac}\right). \tag{1}$$

Inspecting Eq.(1) one find that Vp itself is not an independent parameter but depends on Tac and P, as seen on the experimental results, see Fig.7(b). But, fixing the gas injection pressure, the longer is the accumulation time the higher will be the static column and the greater will be Vp. This fact lead to an increase on the average flow rate but it is not always true because Tac, also appearing on the denominator, may lead to a decrease on Q. The changes on Vp and on the denominator of Eq.(1) have opposite trends as suggested in Fig.8 indicating that Q has a maximum.

Making an assumption that Vp is linearly dependent on TG Eq.(1) can be expressed as:

$$\bar{Q} = Q_0 \cdot \frac{TG}{\left(T_{inj} + T_{ac}\right)}, \tag{2}$$

where Q_0 is a linear constant which has flow rate dimension. Equation(2) has the advantage that its remaining parameters, TG, Tinj and Tac can be determined. TG is measured by the capacitive sensor; Tinj is defined by the PLC and Tac comes from the difference between the cycle period and Tinj noticing that T is defined by the supervisory system. The maximum flow rate can be determined experimentally without the need of the specifying Q_0. With the cyclic assessment of TG, Tinj and Tac the PLC can search for the maximum of Q by setting successive small variations on Tac. The crosses in Figure 8b suggest the measured dimensionless flow rate, Q/Q_0, as a function of Tac; the continuous line represent the curve trend and the maximum flow rate point lies.

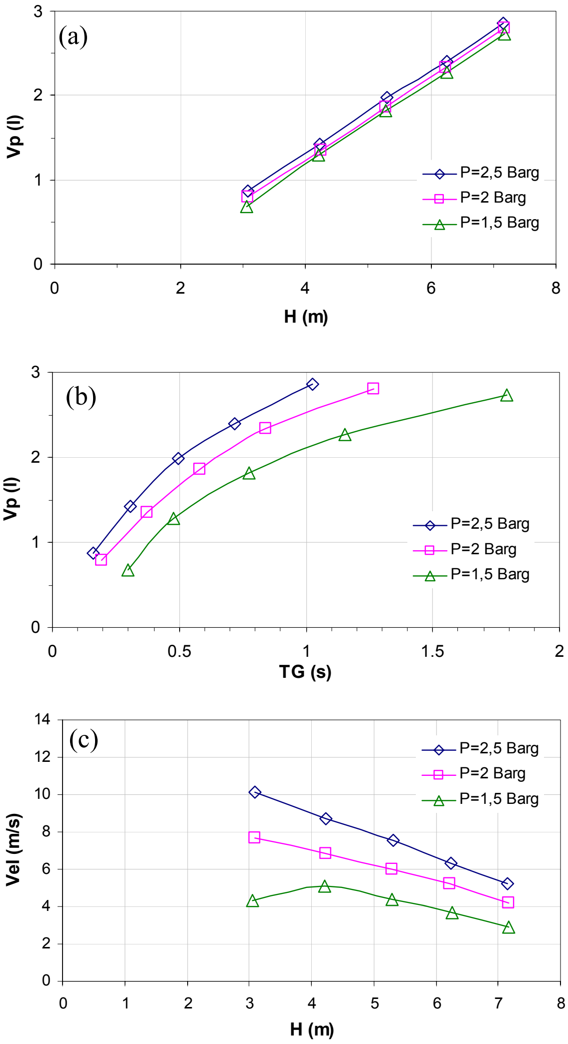

Figure 7- (a) volume of produced water as a function of the static column height; (b) volume of produced water as a function of the residence time; (c) averaged velocity of the produced liquid slug as a function of the static column height. All data taken for valve aperture time, Tav, of 2s and three distinct gas injection pressure.

The experimental determination of the maximum flow rate depends on two assumptions: a linear dependence of Vp with TG and a constant gas injection pressure. It is well recognized that the gas injection pressure changes from well to well depending on the well depth, oil characteristics, tube diameter, operating valve bellows pressure among other parameters. But, considering a specific well it is expected that the injection pressure will be fairly constant to support the second assumption. The linearity between Vp and TG was not observed on the experimental data and this is certainly the weak point on the method. Nonetheless any may support a linear representation in the neighborhood of a point. Despite of this weakness it is still to be verified in field conditions how far from the linear behavior actual IGI systems are.

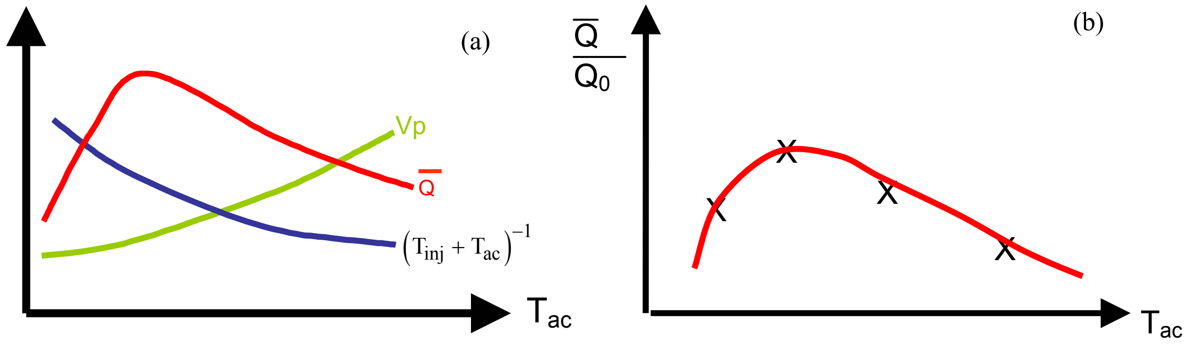

Figure 8 – (a) Trend representation of Vp , (Tinj+Tac)$^{-1}$ and the averaged flow rate per cycle as a function of the accumulation time; (b) dimensionless averaged flow rate as a function of Tac

As a closure note it is presented a distinct approach to determine the functional dependence of the flow rate on Tac. It is based on the assumption that the RPI is a constant, therefore the static column height can be determined from a first order ODE resulting in:

$$\frac{H(t)}{He} = 1 - e^{-T_{ac}/\tau} \quad \text{onde} \quad \tau = \left(\frac{A}{RPI \cdot \rho_o \cdot g} \right), \tag{3}$$

where He is the maximum height that the liquid column can achieve, it is determined by the static head of the reservoir. τ is the time constant that depends on the tube cross section area, A; the RPI, the oil density, ρ_o; and the gravitational constant. Furthermore, based on the experimental evidence of Fig. 7a it is plausible to expect a linear relationship between the static column height and the produced volume to the surface, therefore the averaged flow rate can be expressed as:

$$\overline{Q} = \frac{A_0 \cdot He \cdot \left(1 - e^{-T_{ac}/\tau}\right)}{T_{inj} + T_{ac}}, \tag{4}$$

where A_0 is the proportionality constant between H and Vp and it has unit of linear dimension squared. Expressing Eq.(4) in dimensionless format one finds:

$$\frac{\overline{Q}}{Q_\tau} = \frac{\left(1 - e^{-T_{ac}/\tau}\right)}{T_{inj}/\tau + T_{ac}/\tau} \quad \text{where } Q_\tau = A_0 \cdot He/\tau . \tag{5}$$

The dimensionless flow rate, Eq.(5), is in Fig. 9 as a function of Tac/τ for three dimensionless injection times of 0.01, 0.1 and 1. Each curve exhibits a fast growing rate for low Tac/τ ratio, reaches a maximum and decreases slowly. Comparing Eqs.(2) and (5) results that:

$$\frac{TG}{T_{inj} + T_{ac}} = \frac{\left(1 - e^{-T_{ac}/\tau}\right)}{T_{inj}/\tau + T_{ac}/\tau} \; . \tag{6}$$

Equation (6) expresses equality but its left hand side is determined experimentally while its right hand side is evaluated from an RPI data. The maximum flow rate can be estimated by both methods but one is based on simple experimental measurements while the other needs the RPI curve which is not always available or as accurate as desired.

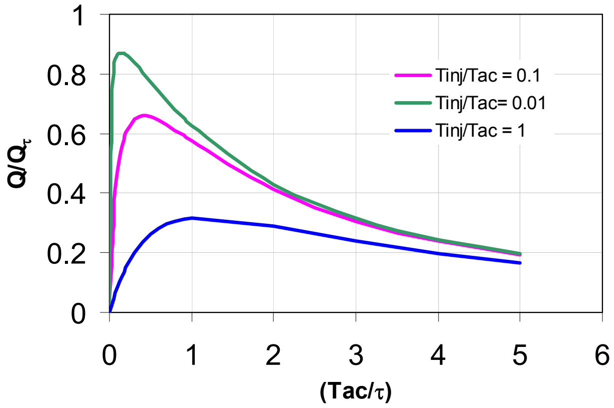

Figure 9 – Dimensionless flow rate, Eq.(5) , as a function of dimensionless accumulation time.

6. CONCLUSIONS

It is proposed an optimization method for the averaged flow rate production based on the liquid slug residence time measurement at the well surface. Presently the IGL operations do not have available a direct measurement of the produced volume per cycle. The measurement of the residence time by capacitive sensor provides an estimate proportional to the produced volume per cycle. A sequence of tests with step changes on the accumulation time will form a data basis of TG, Tinj and Tac which will allow to pin point the maximum flow rate. The strong point of this method is the possibility to achieve the maximum flow rate for each individual well accordingly to its own characteristics. Furthermore, if the well characteristics change in time due to increase in water or free gas contents or even by lowering the reservoir pressure the method is capable to adjust itself to the new operational point.

The experimental study on the IGL method based on down sized facilities in conjunction with the advances in the design of the capacitive sensor gave the necessary conditions to propose the optimization method. These developments are the first steps toward the oil field production optimization for IGL method. The next step will be a field campaign in Miranga field at Bahia state. The successes of these tests will define the next steps on the flow rate optimization based on automated control.

7. ACKNOWLEDGMENTS

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