



# Experiences and Best Practices in the use of PCP's in Orinoco Belt Carabobo Area, Venezuela.

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## Abstract

*Since 90's evaluation of progressive cavity pumps (PCP) in the Orinoco Belt Carabobo Area has been an alternative to handle low and high well production of 8 degrees API of heavy oil.*

*Nowadays, this artificial lift method represents 50% of the productions wells in this area and 45% of the daily production.*

*However during the PCP implantation process, it has been necessary to introduce improvements such as a better pump design, well completion, fluids handle, operational improvements and new technologies application, in order to enhance well production, increase the system run life and reduce the production costs.*

*Examples of best practices and technologies that have been implanted area explained as follow:*

*Gas Separators have been installed in vertical and slant wells (2001 – 2003) and recently (2006) in horizontal wells.*

*Insert systems in order to reduce the work over costs.*

*Best practices in high rate PCP's: 6,16 bpd per RPM pumps have been evaluated and implemented since 1998, we were able to get production rates up to 1500 bpd in horizontal*

*wells. 10,12 bpd per RPM pumps model using 1-1/2" rods and 300 hp motor to produce 2000 bpd, have been evaluated and implemented since 2003.*

*Finally evaluation of PCP with Hydraulic Regulators.*

*This paper presents and describes the experiences that have been introduced in this artificial lift method in Orinoco Belt Carabobo Area, Venezuela and its results.*

## Introduction

The Orinoco oil belt is located on the northern side of the lower Orinoco river in Eastern Venezuela. It covers an area of approximately 20,850 square miles and contains the country's largest deposits of extra-heavy oil, estimated to be  $1.2 \times 10^{12}$  barrels of oil in place (OIP). The Cerro Negro area is located in the eastern part of the Orinoco belt; it covers 70 square miles, with an OIP estimated in  $18.5 \times 10^9$  barrels of extra-heavy oil (Fig. 1).

The extra-heavy oil that is currently being produced in the area has gravity values ranging between 6 and 10°API, with an

average value of 8.5°API, and viscosities of 2,000–5,000 cp at a reservoir temperature of 130°F.

To be able to exploit the extensive extra-heavy oil reserves economically, the drilling and production technology implementations have been significant over the last ten years, particularly the use of horizontal and multi-lateral wells and the development of artificial lift systems, resulting in new production targets of 2,000 BOPD per well compared to the former 200 BOPD.

The use of these PCP production methods reduce the lifting cost and increase the reliability of the system. The applicability of this artificial lift method is presented in this paper.

## Reservoir Description

The reservoir of interest in the Cerro Negro area is of Miocene age, consisting of unconsolidated sandstones with moderate intercalations of shale and saturated with extra-heavy oils. Reservoir quality is excellent, with porosities of 32% and permeabilities of 12 Darcy. The reservoir drive mechanisms are compressibility of rock and fluids and solution gas drive. The most relevant reservoir properties are as follows:

Depth (ft)	3,000–3,600
Pay zone thickness (ft)	280
Reservoir pressure (psi)	1,126
Reservoir temperature, $T_r$ (°F)	133
Oil gravity (°API)	7.4–8.5
Solution gas/oil ratio (scf/STB)	86
Oil formation volume factor (bbl/STB)	1.0847
Viscosity at $T_r$ (cp)	5,500
Porosity (%)	32
Permeability (Darcy)	12
Vshale volume (%)	12
Initial water saturation (%)	18

Table 1. – Typical Reservoir Properties For The Carabobo Area

## PCP Top-Drive (High Rate)

### PCP (6.16 bpd/rpm)

The first high-rate PCP was installed in late 1998 in horizontal well CD-38 of Petróleos de Venezuela S.A. (PDVSA). This well has a 150-ft long tangent section with an inclination of 60° (Fig. 2). It was fitted with 9 5/8-in. surface casing and a 7-in. slotted liner with 0.02-in thick grooves to complete the 2700-ft horizontal section. The PCP system installed in this well had the following characteristics.

- Pump: nominal capacity of 6.16 bpd/rpm, 5,200-ft head.
- Sucker rods: 1 1/4-in. × 25-ft slimhole.
- Downhole pressure sensor to measure intake pressure ( $P_i$ ) and intake temperature ( $T_i$ ).
- Production tubing: 5 1/2-in.
- Top drive: 2 motors, 75 hp (150 hp).
- Variable speed drive: 150 hp.

More than twenty installations with the design above were implemented in the area between 1998 and 2007. The production rates range between 800 and 1,500 B/D, with pump

intake pressures of 500 psi to maintain a high and constant flow rate and 24 months of run life average.

### PCP (10.12 bpd/rpm)

Similarly, in 2005 the evaluation of high lifting capacity progressive cavity pumps (10.12 bpd/rpm and 5996-ft head) begun as an alternative to high-flow horizontal wells with sections extended up to 4000 feet. According to the experience with these equipment in the extra-heavy oil area, it has been possible to handle production rates up to 1900 B/D with maximum operating speed of 280 rpm and with a lifetime of 33 months. Currently these pumps are installed in 6 active horizontal wells of the area.

The PCP system installed in this well had the following characteristics.

- Pump: nominal capacity of 10.12 bpd/rpm, 5996-ft head.
- Sucker rods: 1 1/2-in. × 25-ft slimhole.
- Downhole pressure sensor to measure intake pressure ( $P_i$ ) and intake temperature ( $T_i$ ).
- Production tubing: 5 1/2-in.
- Top drive: 2 motors, 150 hp (300 hp).
- Variable speed drive: 300 hp.

## Gas Separators

Since 1995 in the Carabobo area the installation of PCP begun in vertical and deviated wells, with successful results in terms of production and lifetime of the pumps.

Currently, due to the depletion of the reservoir, high GOR values have been generated (>1000 SCF/STB), affecting the pumping efficiency of the PCP (< 30%) and decreasing the lifetime of the pump caused by high friction and low lubrication between the rotor and stator.

Because of the reasons mentioned before, in the year 2002 begins the evaluation of gas separators with PCP, being this equipment a static helix separator (Fig. 5), which combines the effect of turbulent and centrifugal flow to separate gas from liquid.

Some of the benefits of the gas separators, are the following:

- Increase of the pumping efficiency by increasing the gas/liquid relationship inside the pump.
- Increased liquid production in the well.
- Reduce the effects associated with CO<sub>2</sub> and H<sub>2</sub>S (corrosion and abrasion) in tubing, casing and rod string.
- Increase the lifetime of the elastomer for the following reasons:
  - Reduce heating elastomer by gas bubbles.
  - Better lubrication inside the pump.
  - Reduction of the rotor-stator contact.

The results obtained from the evaluation of 10 wells, are the follow:

- Increased production: 630 bpd (45% increase production).
- Increased lifetime of the pump: 12 to 19 months.
- Increased pumping efficiency: 20 to 25%.

In 2006 there was a reassessment of the gas separators in the horizontal wells CHB 40 and CO 06, at 150 rpm, in this opportunity an average increase of 11% of production associated with the two wells was revealed (Oil production increase: 90 STB)

After the installation of the gas separator in the well CHB 40, the separation efficiency increased by 18%, while in the well CO 06 the efficiency increased by 14,2% (Fig. 7). Additionally, it was noted a decrease in the fluid level of the wells CHB 40 (from 49 to 306 ft) and CO 06 (from 572 to 912 ft) after the installation, which increase the production because there is a good separation of gas before the pump intake, given as result a reduction of the elastomer heating caused by gas bubbles and a better lubrication inside the pump due to gas volume reduction .

## NPCP

Looking to improve the gas handling and to increase the lifetime of the pump, in the year 1997 a NPCP system was evaluated, with a nominal capacity of 3.8 bbls/rpm and 5,900 ft head at the deviated well CI-142 with 4 months of operation.

Two periods of time are observed : 1994 – 2001 , 2002 – 2007 Fig. 8 . GOR ( scf / bbl ) = Gas standard flow rate / Oil flow rate. The average GOR of first period is low ( 185 ) , while the average GOR of second period is much higher ( 2193 ) .

Therefore the gas production of the second period was increased > 10 times the gas of first period . Fig. 9 The OIL flow rate ( bbl/d ) evolution follows the trend : the average oil flow rate of the first period ( 293 ) is higher than the average oil produced during the second period ( 174 ) .

Therefore the field became “ mature “ in 2001- 02: the gas production increases significantly , while the oil production declines .

$$\text{GOR standard} = \text{RGP} = \text{GASF} ( \text{s- Mcf / d} ) / \text{BNPD} ( \text{oil bbl/d} ) \dots \text{equation (1)}$$

$$\text{BNPD} ( \text{oil bbl/d} ) = \text{BTPD} - ( \text{BAPD} + \text{DIL} ) \dots \text{equation (2)}$$

Production flow rate  
Liquid flow rate:

$$Q \text{ liquid} ( \text{bbl / d} ) = \text{BTPD} = \text{Oil} + \text{Water} + \text{Diluant} \dots \text{equation (3)}$$

Standard gas flow rate:

$$Q \text{ sg} ( \text{s-Mcf / d} ) = \text{GASF} \dots \text{equation (4)}$$

Gas flow rate in actual production conditions ( pressure, temperature ), Q gas.

Gas Liquid Ratio in actual production conditions:

$$\text{GLR} = Q \text{ gas} / Q \text{ liquid} \dots \text{equation (5)}$$

Gas Void Fraction ( GVF ) : gas flow rate vs. total flow rate

$$\text{GVF} = Q \text{ gas} / Q \text{ total} = Q \text{ gas} / ( Q \text{ liquid} + Q \text{ gas} ) = \text{GLR} / ( 1 + \text{GLR} ) \dots \text{equation (6)}$$

The standard conditions are :

- temperature : 60°F ( = 520 °R ) or 15.56 °C ( = 289 °K )
- absolute pressure : 14.7 psia or 1.01325 bar

GOR° is related to total liquid flow rate ( BTPD ) ;

$$\text{GOR}^\circ ( \text{scf/bbl} ) = Q \text{ gas standard} / Q \text{ liquid} \dots \text{equation (9)}$$

Gas Liquid Ratio ( GLR ) in *actual production conditions* : pressure , temperature

$$\text{GLR} = \text{GOR}^\circ ( \text{scf/bbl} ) \times [ ( T, \text{ }^\circ\text{R} ) / 520 ] \times [ 14.7 / ( p, \text{ psia} ) ] / ( 5,615$$

Well production	Pressure p = 800 – 600 psi		Temperature T = 130 ° F	
	Q liquid bbl/ d	Qgas stan. s-Mcf / d	GOR° scf / bbl	GVF
25/8/07	250	440	1760	85 – 88 %

$$\text{cf/bbl} ) \dots \text{equation (10)}$$

$$\text{GVF} = \text{GLR} / ( 1 + \text{GLR} ) \dots \text{equation (11)}$$

Notations

- Q ( bbl/d ) total pump delivered flow rate ( liquid+compressed gas )

- Q L ( bbl / d ) pump delivered liquid flow rate

- Q G ( bbl / d ) = Q – Q liquid, pump delivered compressed gas flow rate

The pump performance chart ( 300 TP 1800 ) shows the delivered total flow rate Q ( bbl/d ) and the power P ( HP ) for N = 150 RPM. Taking into account that in multiphase flow the tubing static pressure is depending on the variable gas void fraction , the calculation is an iterative process .

The dynamic pressure drop is negligible comparing with the static pressure ( < 10 % ).

Therefore, considering the intake pressure and the WHP , the pump delivered multiphase pressure is about p ≈ 40 bar .

From the pump 300 TP 1800 performance chart, one can get the delivered total flow rate Q and the power P:

$$Q = 550 \text{ bbl/d} , P = 12 \text{ HP} , \text{ for } p \approx 40 \text{ bar} , N = 150 \text{ RPM}$$

Therefore , the pump delivered performance is :

Date	Q bbl/d	QL bbl/d	Q G bbl/d	GLR	GVF
25 / 8 / 2007	550	250	300	1.12	55 %

At the well head , due to the low WHP = 90 psi ( 6.3 bar ) , the gas decompressed content become very high ; GVF ≈ 85 %

The pump delivered flow rate ( liquid & gas ) is correlated to the pump intake flow rate :

- the liquid volume is constant
- the delivered compressed gas volume is related to the inlet gas flow rate and the pressures:

Pi : intake pressure G

Pd :delivered pressure

Q G,i :intake gas flow rate

Q G,d: delivered gas flow rate.

$$Q G,d= Q G,i(1-\ln(Pd/Pi)) \dots\dots\dots \text{equation (12)}$$

Considering the pump delivered flow rate ( Q G, d ) , one can calculate the intake equivalent gas flow rate ( Q G, i ) that corresponds to the pressure conditions ( p i , p d ) .

Hence , the calculated GVF in *pump intake* conditions can be compared to the GVF obtained through *well measured data* .

The pump intake gas flow ( Q G,i ) based on the pump delivered flow rate (Q G,d ) is :

$$P_i = 35 \text{ bar} , P_d = 75 \text{ bar} , Q G,d = 300 \text{ bbl} / \text{d} , Q G,i = 1261 \text{ bbl/d.}$$

and the calculated intake gas void fraction is GVF = 84 % which is comparable with the well measured data : GVF = 85 - 88 %.

In connection with that , the compressed gas inside the pump corresponds to the calculated flow rates .

25/ 8 / 2007	PUMP		WELL
	delivered GVF	intake GVF	downhole GVF
QL =250 bbl/ d	55 %	84 %	85 - 88 %

Hence , the pump intake calculated flow rate ( GVF = 84 % ) is coherent with the well production data ( GVF = 85 – 88 %).

The pump production flow rate is : Q liquid = 250 bbl/d with a high gas content of GVF = 85-88 %.

The Fig. 10 shows NPCP measured torque and the average value during the period 4/8 /2007 to 16/10 / 2007. The average value of measured torque ( 398 ) is less than the standard value ( 423 ) .

From the pump performance chart ( Fig. 4) we can get the consumed power P ( HP ) related to pump velocity N ( RMP ) .

Then , the standard torque Ts is obtained :

$$T_s (\text{lbf ft})= 554.8 \times (PHP/ \omega (\text{s}^{-1})) \dots\dots\dots \text{equation (13)}$$

$$\omega (\text{s}^{-1})= (\Pi.N (\text{rpm}))/30 \dots\dots\dots \text{equation (14)}$$

Therefore , for N = 150 (RPM ) and p = 40 bar , the consumed power is P = 12 HP and the corresponding standard torque becomes : Ts = 423 ( lbf.ft ) .

## Insertable PCP

Looking to reduce cost associated to interventions with rigs, recently it was evaluated with a insertable PCP system in vertical an horizontal wells, CI 42 an CI 232 respectively, from the Carabobo area.

The description of the insertable PCP system installed in these wells is at the Table 2.

Characteristics	Well CI 42	Well CI 232
Pump nominal capacity	2,013 bls/rpm, 5,200 ft head	5,032 bls/rpm, 5,200 ft head
Sucker rods	1 x 25-ft Slimhole	1 ¼ x 25 -ft Slimhole
Production tubing	4 ½ in	5 ½ -in
Top drive	motor, 75 hp.	2 motor, 75 hp, 150 hp.
Variable speed drive	100 hp	150 hp

Table 2 – Characteristics of the insertable PCP system in the Carabobo area.

The pumps installed in these wells have been operating for 4 to 18 months, respectively, with a leveled production of 40 STB/D for the first well and 300 STB/D for the second. Both wells integrate an anchoring system of friction rigs (Fig. 12)

Among the advantages of this type of pump, there are the following:

- Around 75 % of the regular cost is saved in subsequent installations due to lower installation time and cost if we compared them with the standard service rig.
- Around 50% of service rig time saving, for change a insertable PCP.

This type of artificial lift system is recommended to reduce the cost in matters of rigs operations, because the pumps can be replaced with flush-by or workover rig , with an average saving of 75% of the associated cost (U.S.\$ 20,025). Otherwise, the replacement service of equipment with major capacity rigs increase operation cost by 55,900\$.

With the evaluation and monitoring of the installed equipment in the previously mentioned wells, it is intended to extend this practice to several wells in the Carabobo area.

## Conclusions

- PCP Top Drive High Rate system (6.16 bpd / rpm) production rates between 800 to 1500 STB/D are achievable with an average lifetime of 24 months and with the system of 10.12 bpd / rpm production rates up to 1900 STB/D and lifetime up to 33 months have been managed.
- The assessment of gas separators, in vertical and deviated wells, showed a 45% production increase, the lifetime of the pump rose from 12 to 19 months and increased pumping efficiency from 20 to 25 %.

- The experience with gas separators in horizontal wells, showed improvements in production (11%) and an in the efficiency of pumping (8%).
- Based on experience with the NPCP the pump intake calculated flow rate (GVF= 84 % ) is coherent with the well production data (GVF= 85 – 88 % ). This confirm that the new PCP design can operate in multi-flow conditions and high gas content.
- Measured average torque of the NPCP is compared with the torque standard value. From the pump performance chart we deduce the consumed power (for N = 150 RPM) which enables to calculate the standard torque. The torque is kept under normal conditions with high GVF handled by the pump.
- The insertable PCP provides a saving between 75 to 85% of the cost associated to the replacement of the pump (U.S.\$ 20,025) and around 50% of service rig time saving for change a insertable PCP.

## Acknowledgement

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## NOMENCLATURE

$p$	=	pressure, m/Lt <sup>2</sup> , psi
$T$	=	temperature, T, °F
$d$	=	discharge
$i$	=	intake
$r$	=	reservoir

## SI METRIC CONVERSION FACTORS

bbbl	× 1.589 873	E-01 = m <sup>3</sup>
cp	× 1.0*	E-03 = Pa-s
ft	× 3.048*	E-01 = m
°F	(°F-32)/1.8	= °C
hp	× 7.460 43	E-01 = kW
in.	× 2.54*	E+00 = cm
lbf-ft	× 1.355 818	E+01 = N.m
psi	× 6.894 757	E+00 = kPa
sq mile	× 2.589 988	E+00 = km <sup>2</sup>

\*Conversion factor is exact.

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## Appendices

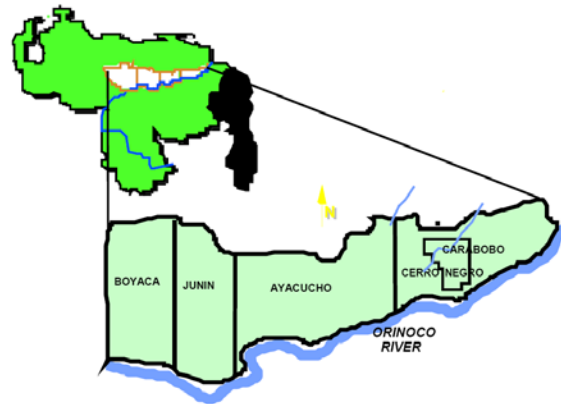


Fig. 1—Location of the Cerro Negro Area in the Orinoco oil belt, Venezuela

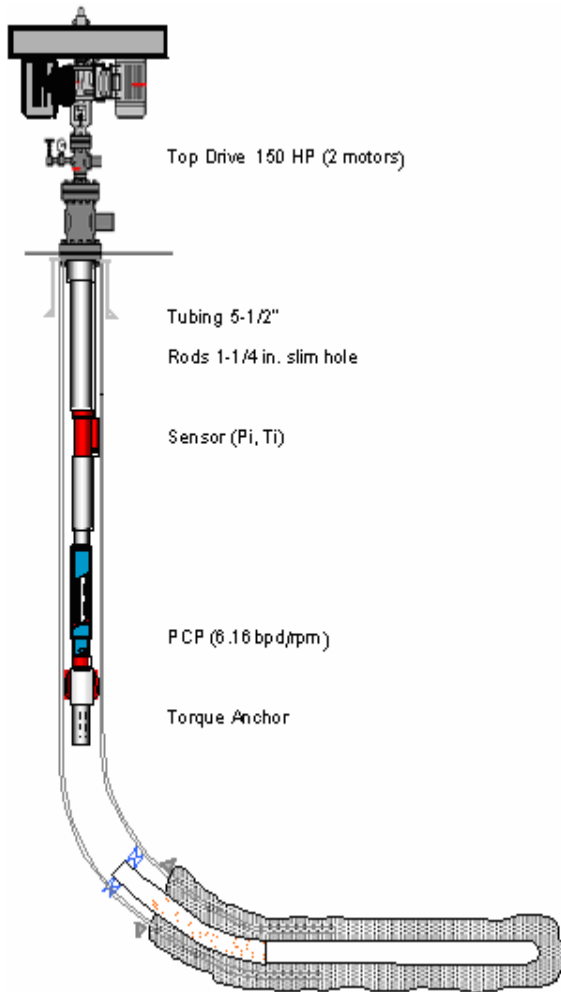


Fig. 2—Completion schematic of Well CD-38

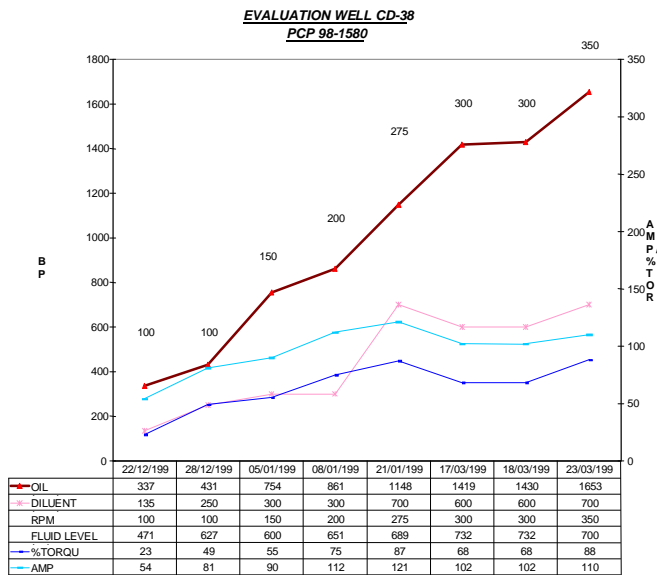


Fig. 3—Behavior of the Well CD-38

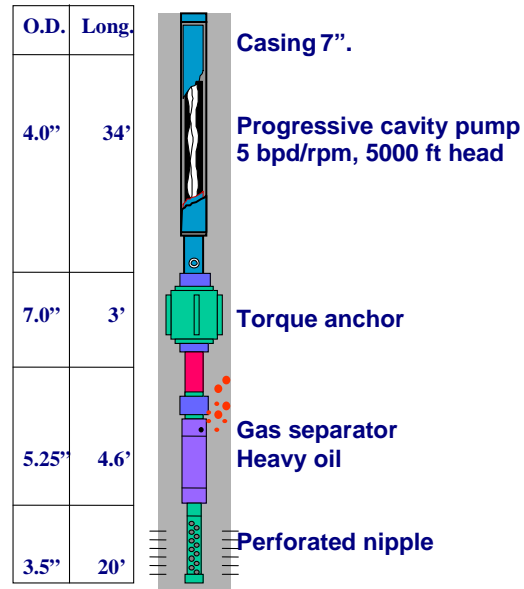


Fig.4 —.Diagram of completion with gas separator.

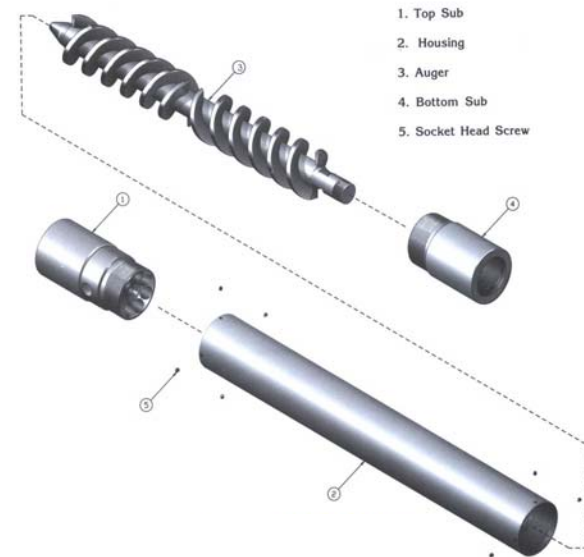


Fig.5— Internal sketch of the gas separator.

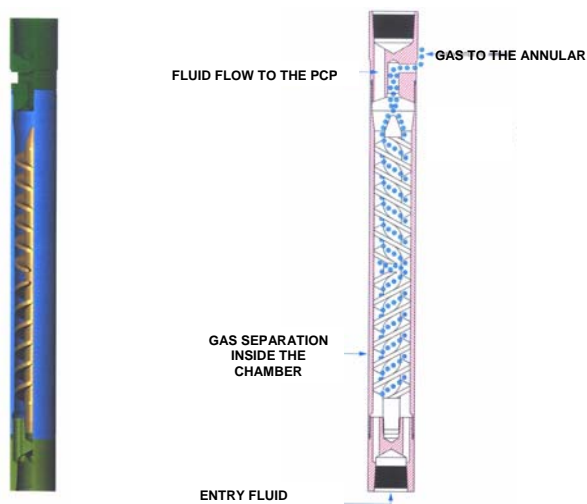


Fig.6 — Operation of the gas separator.

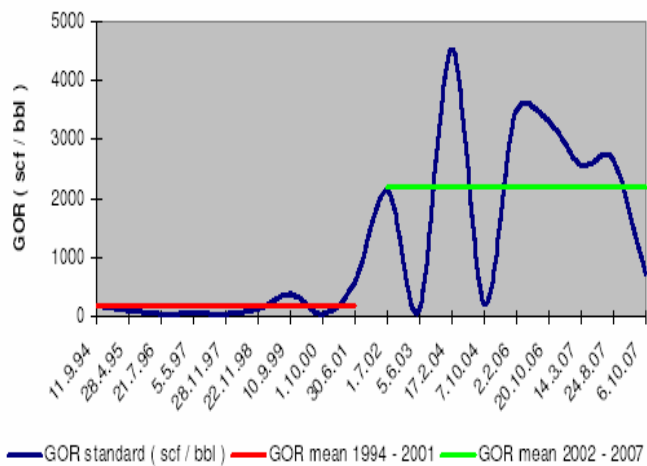


Fig. 8— GOR ( cft/bbl ) in standard conditions .

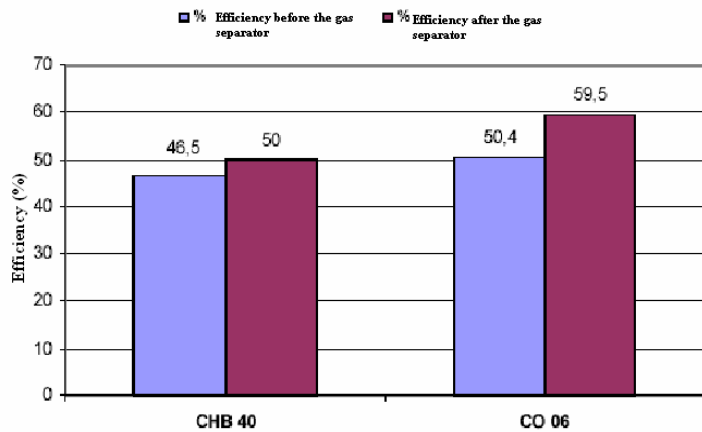


Fig.7 — Pumping efficiency before and after the installation of the gas separator.

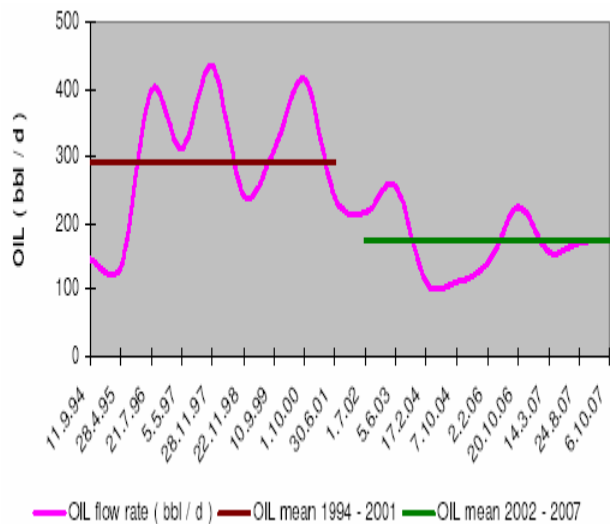


Fig. 9— Oil flow rate ( bbl / d ) .

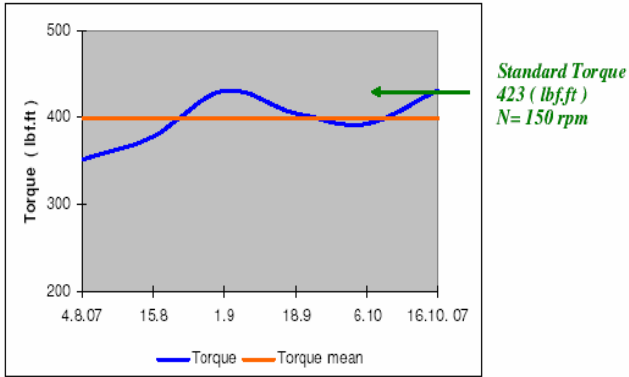


Fig. 10 — Measured NPCP torque and the average value during the period 4.8 .2007 to 16. 10 . 2007

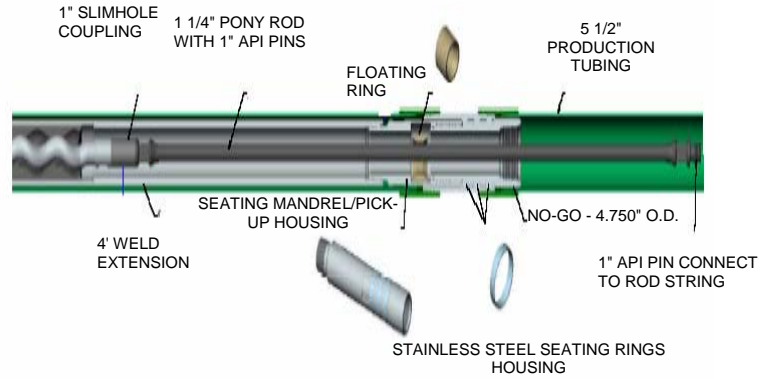


Fig. 12— Scheme completion with insertable PCP with friction rings.

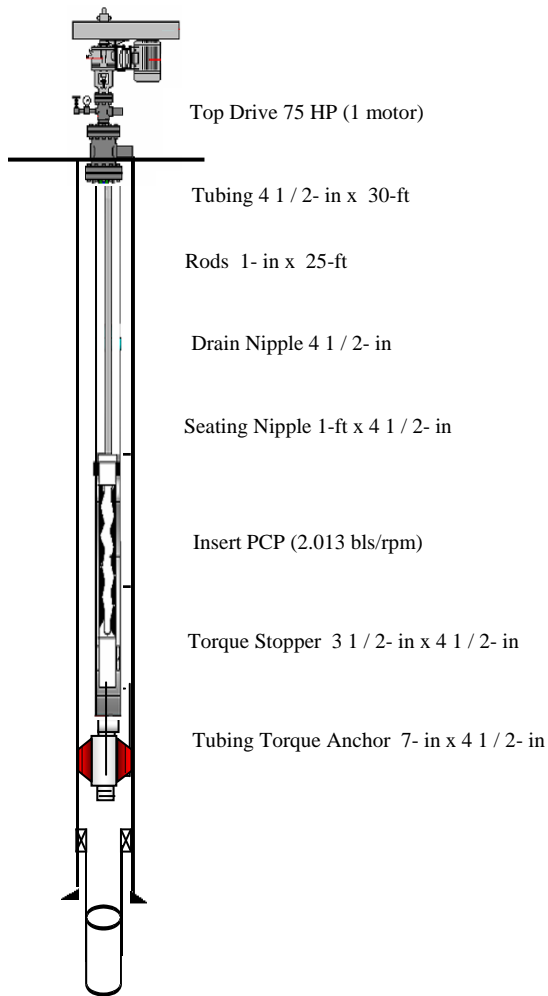


Fig. 11—Completion schematic of Well CI-42