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Experiences in the Use of ESP's in Orinoco Belt Cerro Negro Area, Venezuela

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Abstract

Traditionally, in the Cerro Negro area up until 1995, conventional rod pumping units and progressive cavity pumps were used in vertical and inclined wells with production rates ranging between 200 and 600 b/d.

With the incorporation of the horizontal drilling technologies in unconsolidated sands for the construction of wells with high productivity indexes (4-6 b/d/psi), the evaluation of electrical submersibles pumps (ESP) begun as an alternative to handle high production volumes of 8 degrees API bitumen characterized by its viscosity of 5500 cp at a reservoir temperature of 130°F.

To aid production, a dual well completion design was used, parallel to the production tubing a second tubing with a smaller diameter was installed to allow diluent (32°API) injection at the bottom of the wells, diluting the bitumen from 12.5 to 13.5 °API, an decreasing its viscosity to a range of 500-800 cp . Additionally, buy lowering the viscosity gas separation was aided before the intake of the pump.

At the beginning of the project, ESP's with nominal capacities of 4000 b/d of flow were installed in re-entry wells, diluent injection was done using ½" coiled tubing attached to the production tubing parallel the power cable, reaching production rates in the order of 800 to 1000 b/d of bitumen. Subsequently, in new horizontal wells, ESP's with capacities of 8000 and 6000 b/d of flow were installed, and two different diluent injection string designs were used.

The first design used was two 1/2"coiled tubing strings assembled with the power cable, with this system diluent was injected at the pump level; the second design was regular 1,5-1,9" cs-hydrill tubing strapped to the production string, allowing diluent injection below the pump, at the top of first slots in the horizontal liner

This second system was selected as standard together with ESP with a nominal capacity of 6000 b/d. Bitumen production rates ranging from 1500 to 2000 b/d of bitumen are obtained by injecting 400 to 600 b/d of diluent, decreasing friction losses and obtaining an average of 30% of pump efficiency. Additionally, the use of the system has increased the run life of the pumps, actually 33 months.

To improve the efficiency of the ESP pumps new devices are being tested, an inducer was installed in substitution to the down hole gas separator. Simulations indicate that this device, placed at the intake of the pump, will permit gas handling through the pump, decreasing the fluid column weight.

Introduction.

Orinoco Belt is located in Venezuela, at the north of Orinoco river, it cover an area of 54.000 sq. kilometers, with 24.2 billion barrels of bitumen originally in place. Bitumen is commercially extracted to produce Orimulsion®, a fuel used to produce electricity.

Extracted bitumen has an API gravity between 7,4 to 8,5 degrees. Average is 8.0 API degrees. Viscosities is from 2000 to 5000 centipoises at reservoir temperature of 130 F degrees.

For bitumen extraction, perforation and production techniques have been improved. Last 10 years have been of big technology advances, with the inclusion of horizontal wells and new artificial lift methods, which have increased productivity from 200 b/d to 2000 b/d.

Reservoir description.

Reservoir is conformed by unconsolidated sands, bitumen saturated, with some shale intercalation.

Characteristics of flowing and rocks are as follows:

Reservoir Pressure (Psi)	1180
Reservoir Temperature (degrees F)	120
Rsi (SCF/ STB)	86
Boi (STB/ STB)	1.061
Pay Zone (Feet)	280
Depth (Feet)	3000-4000
Oil Gravity (degrees API)	7.4- 8.5
Porosity (%)	30- 35
Permeability (Darcies)	7
Vshale volume (%)	6
Swi (%)	18
Viscosity, (centipoises)	5500

Reservoir production mechanisms are solution gas drive and rock and fluid compressibility.

ESP´s in reentries wells.

In 1995 with the introduction of reentrie wells of high productivity indexes (1-3 b/d/psi) and searching high bitumen production rates, the first ESP's were installed. Configuration of reentries wells (Fig. 1) was open window at the 7" casing above original abandoned with 4 ½" cement plug, slotted liner was used for the 1500' of horizontal section. The ESP was installed at the vertical section, above the plug. Two ESP's were installed at wells CC-07 and CD-01. Next, characteristics are as follows (Fig. 1);

Pump, nominal capacity of 4100 b/d of flow (141 stages).
Rotary Gas Separator
Seal section of an elastomer bag plus two labyrinthic cameras.
Two series Motors 195 hp/1055volts/105 amp, with 390 hp of capacity.
Down hole pressure sensor.
Power cable # 1, flat.
Variable speed drive of 390 kva.

Due to high bitumen viscosity (5500 cp), it is necessary down hole diluent injection, in order to reduce friction loses and increase pump efficiency. The diluent used is 32 API degrees and pumped from the flow station to the wellhead at 450 psig. Diluent injection was done using ½" two coiled tubing together with the power ESP cable attach to the 3½" production tubing with bands. Below the ESP was installed a centralizer that made the function of an injection sub, where the ½" tubings were connected, injecting the diluent below the suction of the pump, in order to secure that bitumen / diluent mixture flows to the enter of the pump. (Fig. 1).

Before esp installation, these wells were completed with PCP, getting production rates of 300 to 350 b/d. With the installation of the ESP; CD-01 and CC-07 wells productivity were increased up to 1000 b/d and 800 b/d, injecting 200 b/d of diluent in each well (Fig. 2).

ESP´s in horizontal wells.

Well CD-38

Preceded of the success in the reentries wells, at end of 1995 year, first ESP was installed in a horizontal well with of 9 5/8" casing (Well CD-38) and 2700 feet of horizontal section completed with 7" slotted liner and grooves of 0.02" thickness. This well design was done with a tangencial section of 60 degrees of inclination and 150 feet long. Characterisitics of ESP installed are the following (Fig. 3);

Pump, nominal capacity of 8200 b/d of flow (118 stages).
Rotary Gas Separator.
Seal section of double elastomer bag with labyrinthic camera.
Two series Motors of 195 hp/1055 volt/105 amp, adding 390 hp of capacity.
Down hole pressure sensor.
Power cable # 1, flat.
Variable speed drive of 454 kva.

Diluent injection was done using a 1.5" cs-hydrill tubing strapped to the production string by clamps, allowing diluent injection 90' below to the pump.

Speed of the ESP (hz) was increased progressively, in order to to produce a maximum production rate of 2000 b/d, injecting 500 b/d of diluent down hole (Fig. 4). Subsequently production declined and it was optimized with diluent injection down hole and at the surface in order to reduce wellhead pressure. Best results were reached with diluent inyection of 1400 b/d. Diluent injection across the annular section was eventualy used in order to increase pump efficiency.

A disadvantage of this model was that wellhead pressure increased and affected production rates in great measurement. That's why diluent injection at the surface was used in order to secure proccess conditions.

Closter I-21-2.

At the final of 1996, three horizontal wells were drilled in closter !-21-2, each one with 2000 ft horizontal section, these were completed with electrical submersibles pumps. Equipments with low volumetric and electric capacity were installed, in order to optimize design according to the experiencies reached in previous wells. Their characterisitic were as follows; (Fig. 5):

Pump, nominal capacity of 6100 b/d of flow (106 stages).

Rotary Gas Separator.
Seal section with double elastomer bag labyrinthic camera.
Motor of 304 hp/ 2290 volt/ 81 amp.
Down hole pressure sensor.
Power cable # 1, flat.
Variable speed drive of 325 kva.

First two wells were installed using flat cable assembled with two ½" coiled tubing (Fig. 5) for diluent injection in order to optimize the completion time. However, there were blockage problems with the ½" coiled tubings. Completion design was changed using tubing of 1.5," permitting high diluent rates down hole.

Optimization of the equipment dimension was not completely favorable, capacity of variable speed drive of 325 to 390 kva was needed, in order to increase frequency up to 60 hz (maximal operation speed).

In this closter, production rates of 2500 b/d at 60 hz have been reached, injecting 600 b/d of diluent down hole. Actual average production rate is of 1500 b/d by well. However, bitumen production decreases notably once rpg increases (Fig. 6).

Re-design stage.

Volumetric and electrical capacities of the equipments installed in 1997 and 1998 were increased in order to increase production, as follows (Fig. 7):

Pump, nominal capacity of 6100 b/d of flow (118 stages).
Rotary Gas Separator.
Seal section of double elastomer bag labyrinthic camera.
Motor of 342 hp/ 2290 volt/ 81 amp.
Down hole Multisensor: Intake Pressure, Motor temperature, Intake temperature, Current loses and vibration.
#2 Power cable, rounded. In these designs, cable protectors were installed at tubing couplings, in order to reduce the continuous faults in the power cable during the installations.
Variable speed drive of 390 kva.

Diluent injection was done with 1.9" cs-hydrill tubing strapped to the 4 ½" production string with clamps, allowing diluent injection below the pump at the top of the first slots in the horizontal liner, obtaining better diluent + bitumen mixture (Fig. 7).

Production rates didn't increase, however pumps it increased pumps run life (during first year of operation average production per well was 1500 b/d). This was the result of maintaining the production rates at medium constant frequency (40 to 45 hz), maintaining pump intake pressure between 500 and 600 psi (Fig. 8). Utilization of presurre and temperature multisensors of high precision and better technology have allowed to control down hole conditions.

Long term results reflected the necessity of high horse power at early stage of the well, since subsequently reservoir declination generates cause an increase of GOR, unloading fluid column and diminishing power requirements. Other additional aspect is that maintaining medium pump speed and controlling pump intake pressure has gotten a high and stable production rates for a longer period of time, increasing reservoir recovery factor.

Standardization of design.

With two previous conclusions deduced, designs installed during 1999 and 2000 have had the same characteristic of the equipments installed at the end of 1996;

Pump, nominal capacity of 6100 b/d of flow (106 stages).
Rotary Gas Separator (in some cases substituted by inducer).
Seal section of double elastomer bag labyrinthic camera.
Motor of 304 hp/ 2290 volt/ 81 amp.
Down hole Multisensor: Intake Pressure, Motor temperature, Intake temperature, Current loses and vibration.
Power cable # 2, round. (Without protector cable, there could be a possible damage during installation).
Variable speed drive of 325 kva.

There have installed eight (8) equipments during 1999 and 2000. In some cases an inducer wich is under evaluation was installed instead of gas separator. It consists in a helix without end, installed at pump intake, permitting the gas to be handled through the pump without gas separation, unloading the fluid column and reducing friction losses in the production tubing.

Production rates have oscillated between 1500 to 2000 b/d, maintaining pump intake pressure on 500 psi (Fig. 9).

There were some cases in which frequency was increased in order to increased productivity. However, wells diminished production in 40% (Fig. 10); pump intake pressure declined quickly, and gas oil ratio increased from 100 to 500 scf/bbl.

Actually, there are in evaluation tapered pumps designs, combining pumps with differents capacities, in order to create a gas compression effect. There was installed a lower pump of nominal capacity for 8200 b/d and an upper pump with nominal capacity for 6100 b/d.

Down hole fault and run life.

In figure # 11, ESP's run life in Orinoco Belt are shown from 1995; which it has been increased from 31 to 51 months.

Run life has increased in time, due to improvements implanted in designs. The first faults (Fig. 12) were occasioned becaused of deficiencies in diluent injection, when pumps installed and completed with ½" coiled tubings failed. Coiled tubing cloged because of high bitumen viscosity, creating electric motor failed. ½" coiled tubing was substituted for 1.5" cs-hydrill tubing parallel to tubing of production.

During the first installations of ESP's, faults in the power cable during installation were occurred. In some cases power cable was flattened or broken with the wedges used to hold production tubing or even with completion casing. For this reason a well protector cable was installed at the curve section of the well.

The improvement of the operacional know-how, the utilization of round cable and the improvement of the arrangement 4 ½" production tubing with the 1.5-1.9" tubing of diluent injection have eliminated the necessity of utilizing protector cable. No fails have occured in the power cable during 2000 year.

Thus, there's been contamination of the seal section with bitumen, contaminating the motor and generating electric failure. There's been a high incidence of these one after a long period of life (an average run life of 29 months).

New Technologies and future challenges.

In search of reducing production costs, hybrid technologies have been evaluated like the ESPCP (Fig. 13), which is a combination of ESP with PCP. It has been evaluated two (2) times.

First evaluation was done in 1997 March, utilizing a PCP with nominal capacity of 616 b/d/100 rpm, motor of 150 hp and gear box of 9 to 1. A maximum production rates of 1992 b/d to 453 rpm was reached with diluent injection at the surface. Run life of this equipment was 12 days and the fault was originated in the gear box.

Second evaluation was done in August 1998, utilizing the same type of PCP, with a motor of less power (133 hp) and gear box of 9 to 1. Maximum production rates was 1200 b/d at 407 rpm, also with diluent injection at the surface. Its run life was 36 days, the fault was in the flex shaft that connects the gear box with the rotor of PCP.

In spite of the results mencioned before, there's been waiting for the improvement of this technology, since it's a good alternative in order to get the same production rates with ESP but reducing costs.

In order to improve productivity we are looking for new technologies in order to get higher efficiency pumps to reduce power requirement, to increase gas handling efficiency or more efficient separation, improvement of downhole bitumen + diluent mixing., reduction of faults and new production methods.

Conclusions

1. In wells with ESP downhole diluent injection is needed, in order to decrease friction losses, to increase pump efficiency and optimizing pump operation..
2. The standard system for Bitor Cerro Negro horizontal well with ESP, it is a pump with nominal capacity of 6000 b/d with diluent injection though 1.5-1.9" cs-hydrill tubing attached to the 4 ½" production tubing.
3. Power requirement for ESP's is 304 hp, Bitor Cerro Negro experiences shows us the necessity of high horse power in the early stage of the well, since subsequently the reservoir declines generating an increase of the GOR.
4. Contamination of the seal section with bitumen from the well produce a damage in the motor. This is one of the most common failures after a long run life of the equipment (run life average of 29 months).

References

1. Espinoza, M.R. and Montefusco, L.E.: "Evolution of the production methods for bitumen in the area Cerro Negro of the bituminous Orinoco Belt – Venezuela", UNITAR N° 062.
2. González Reina, Briceño Marcos: "Optimización de Pozos Reentry, Area Cerro Negro" February 1996.
3. Velásquez Aníbal "Desarrollo de la Perforación y Producción de pozos en macollas en el Área de Cerro Negro" July 1996.

Figures

Figure 1- Reentry well with ESP

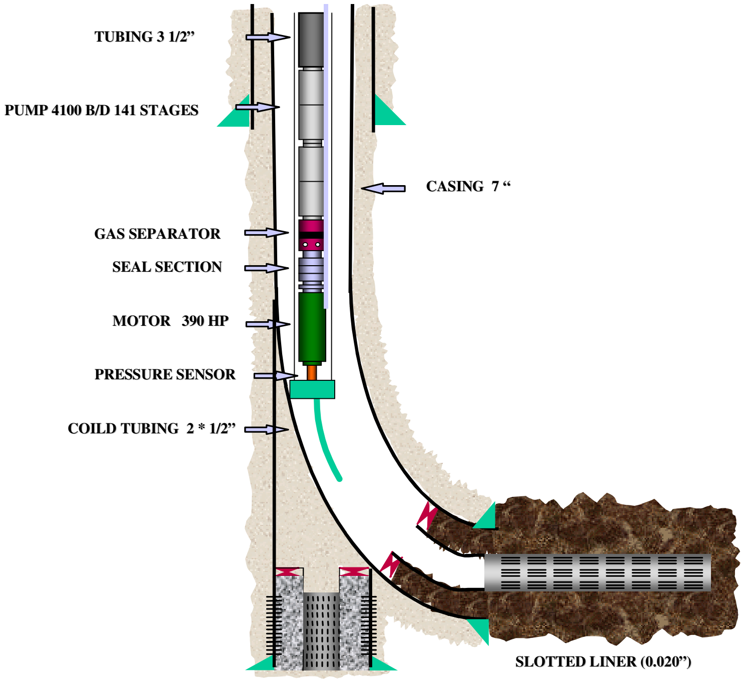

Figure 2- Production reentry well

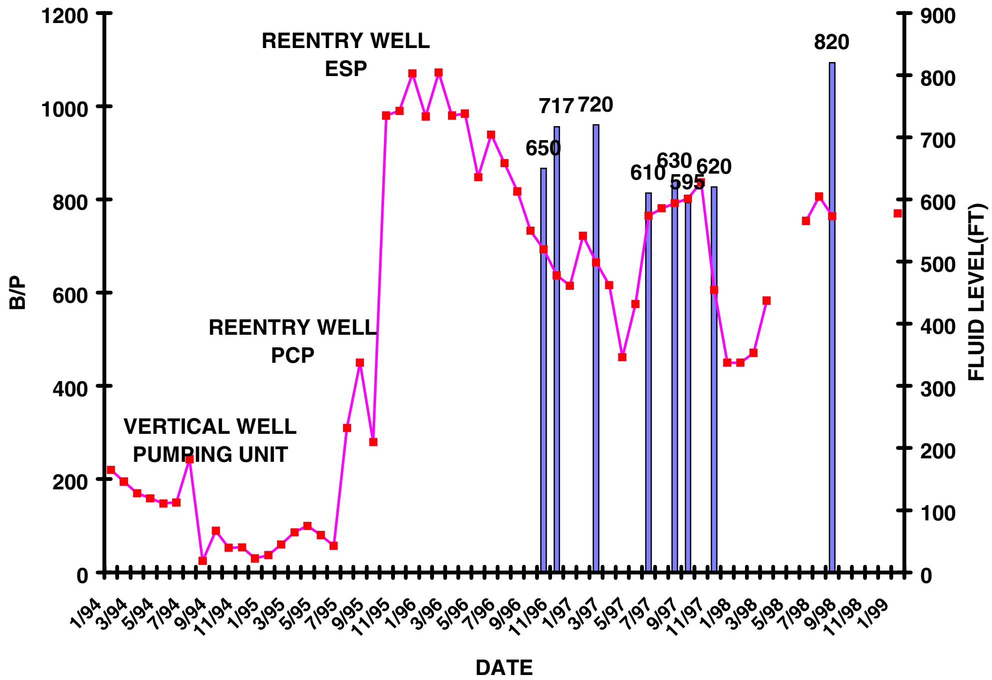

Figure 3- Well CD-38.

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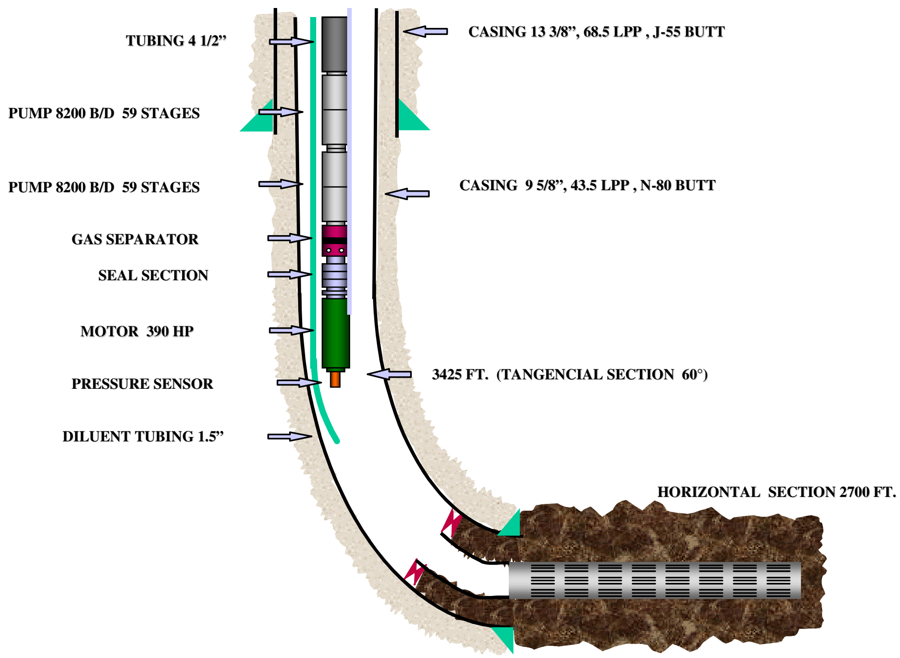


Figure 4- Production well CD-38

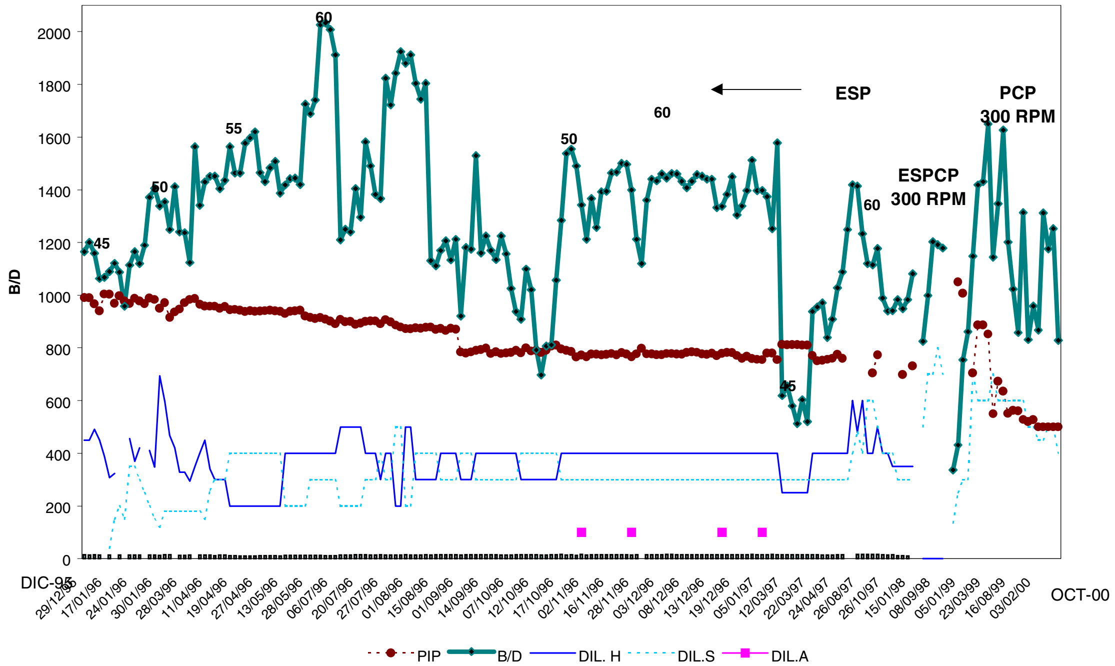


Figure 5- Wells of closter I-21-2.

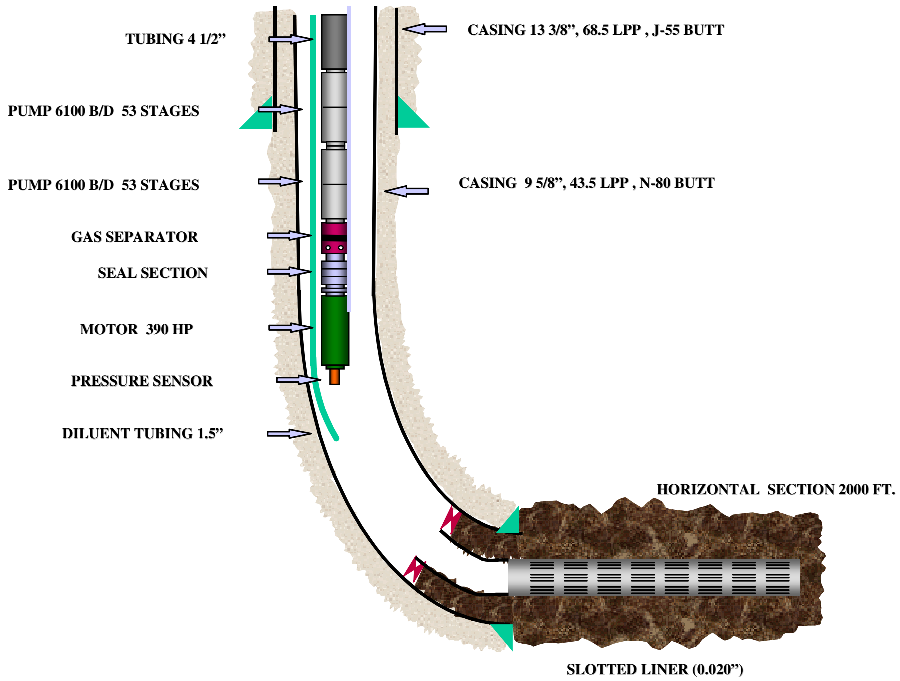


Figure 6- Production well CI-225 (Closter I-21-2)

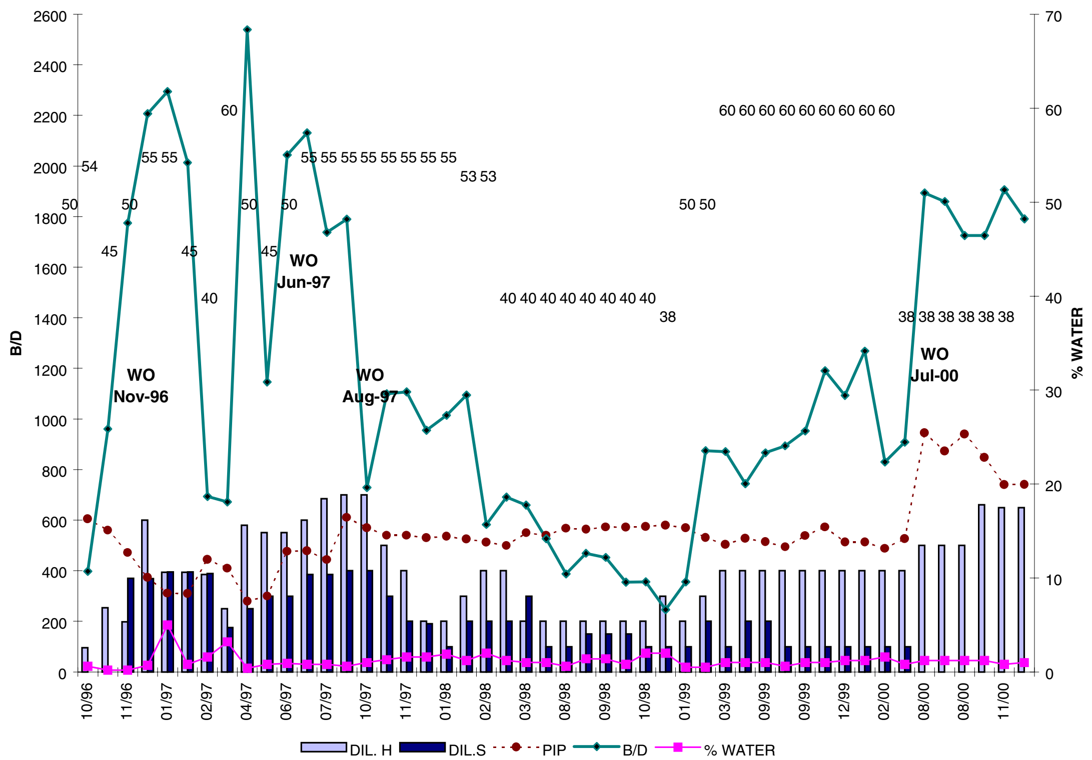


Figure 7- Well CI-229.

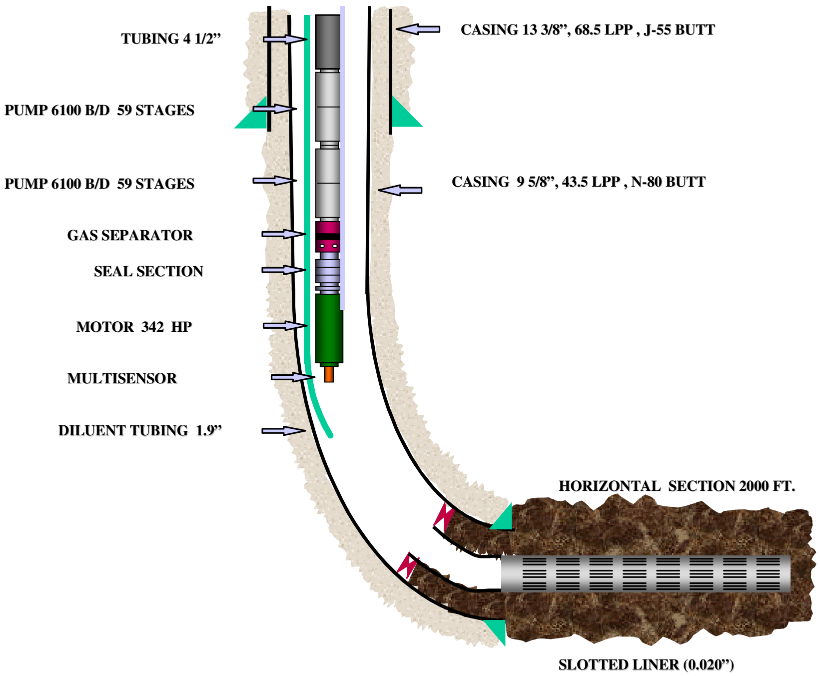


Figure 8- Production well CI-227

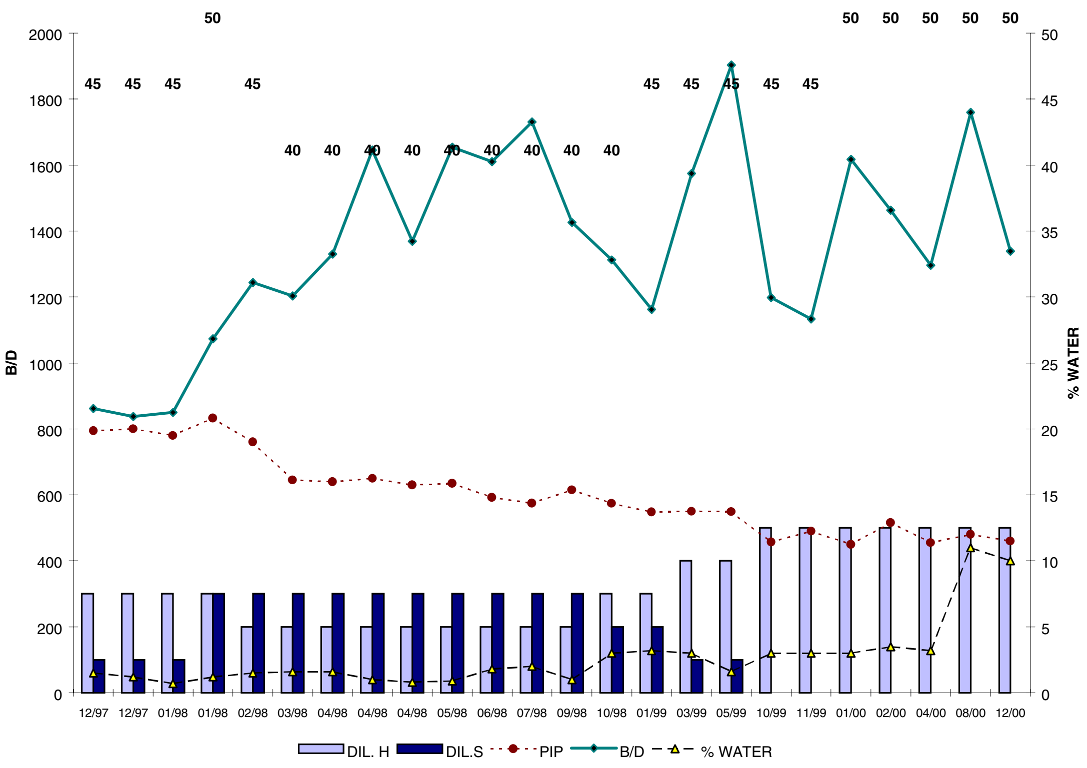


Figure 9- Production Well CI-236.

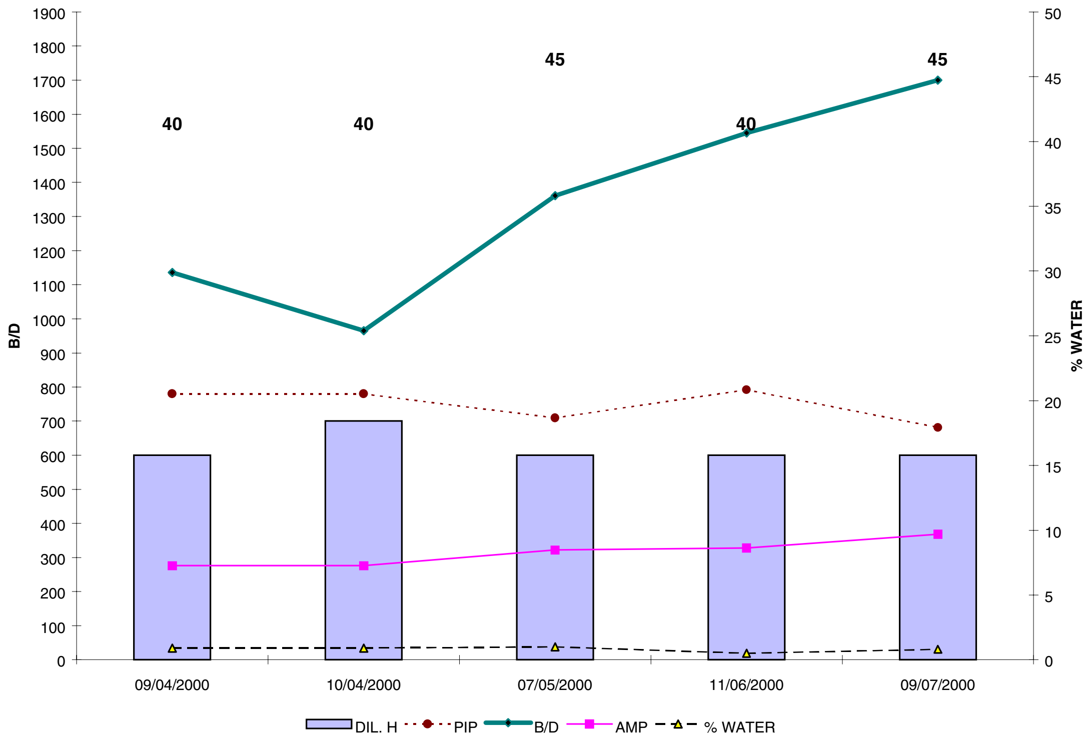


Figure 10- Production Well CI-233.

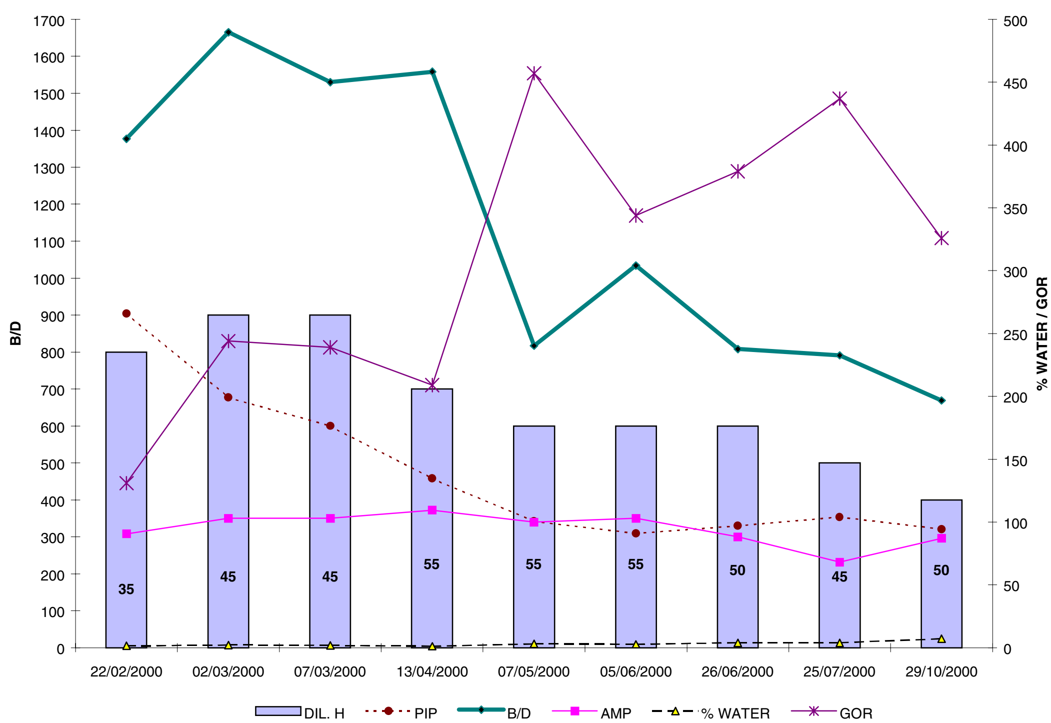


Figure 11- ESP's Run life

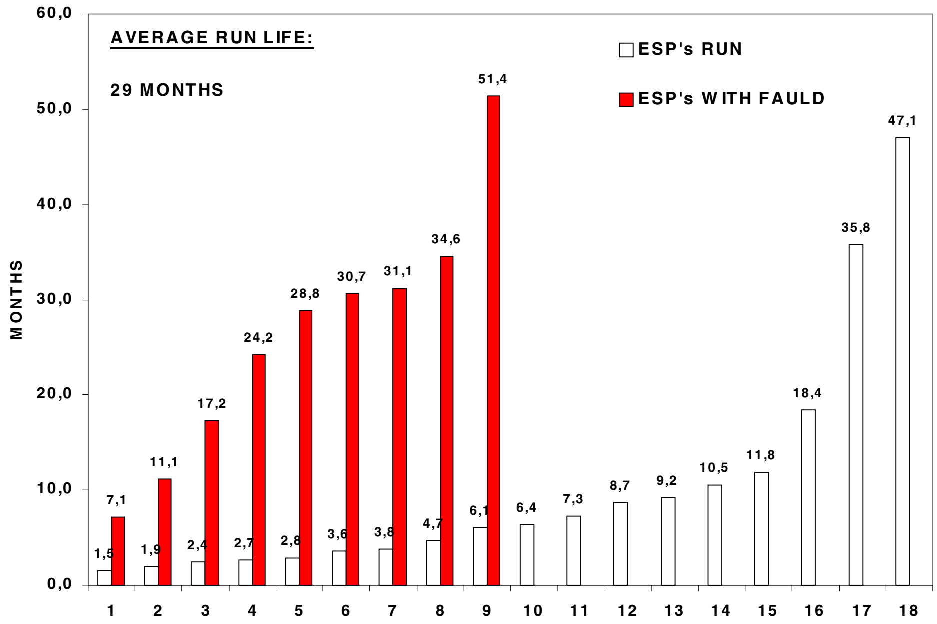
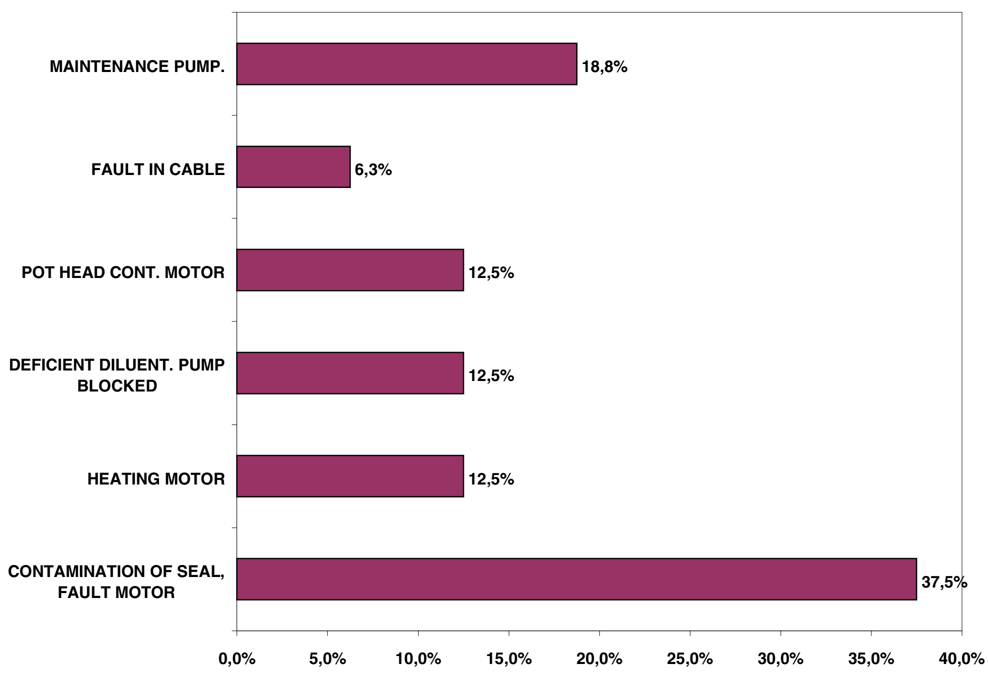


Figure 12- Faults in ESP's.



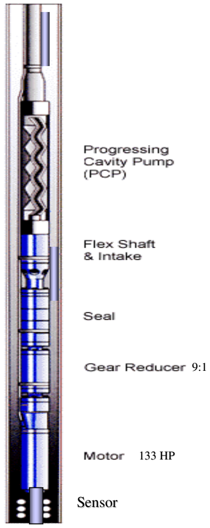


Figure 13- ESPCP.