STATIC GAS SEPARATION INCREASES ESP EFFICIENCY IN COLOMBIAN FIELD

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ABSTRACT

Some Colombian oilfields have medium to heavy oil production and high gas volume in wells. Gas production is one of the biggest limitations in an Electrical Submersible Pump (ESP) system, as they have difficulty handling a large amount of free gas. In many cases, even when an ESP is used in conjunction with a gas separator and gas handlers, the amount of free gas exceeds the capacity of the system and the performance of the pump is decreased.

One complex well in this oilfield produced 2.2 MMscf/day (representing around 18% of the total gas produced in this field). For this application, a double stage gas separation system was designed. The ESP design consisted of a vortex ESP gas separator, gas handler, shrouded ESP + downhole gas separator with the intake installed below the shroud. This combination proved to be successful with an efficient pump performance.

INTRODUCTION

The reduction of investment in the oilfield was one of the biggest problems in 2015 for Colombia. Oil price forced reduced spending and many projects were shut down. With this general view of zero drilling and almost any well services operation in the business plan, engineers had the challenge of maintaining the oil production without incurring significant new expenses. Part of the strategy was to use the gas produced to generate electricity and reactivate closed and/or inactivated wells to reduce the decline curve of the field. One of these wells produced in natural flow since 2012 and it was deactivated in 2014 when the reservoir energy decreased. After this, the well was declared non-operative due to the gas potential reaching 2.2 MMscf/day and the ESP system installed was not able to handle that amount of gas.

Some ESP providers recommended to set the pump deeper to achieve a higher pump intake pressure (PIP) and avoid the free gas at the pump intake. The PIP and the bubble point pressure are the two factors which show whether there will be free gas at the pump intake. If the PIP is below the bubble point pressure, then free gas will be present, but if the PIP is greater than the bubble point pressure, then there will not be free gas present. However, a deeper installation would represent higher operational costs due to the longer power cable needed, more tubing length and installation time. In addition, increasing the PIP would require a sufficiently greater submergence of the pump below the dynamic liquid level causing a high flowing bottom hole pressure severely limiting the well's production rate.

As a first option, the ESP gas separator was considered for this application. This separator is a dynamic gas separator which submits the fluid to centrifugal forces, allowing separation of the less dense fluid. Although there are many types of centrifugal gas separators for ESP, these tools are not 100% efficient and their capacity may be overcome, resulting in a high volume of gas getting into the ESP. For this reason, a pilot project, never attempted before in Colombia, was implemented, which consisted of using a high-performance static/centrifugal gas separator to optimize gas separation before the fluid reaches the pump intake. In this way, the fluid would pass through different paths where coalescence and buoyancy forces will separate the free gas, as it travels up through the casing annulus. Finally, the gas would be converted to electrical energy and sent to the gas plant.

WELL CONDITIONS

The well was completed in February 2012 with an ESP. However, the well showed a high potential to produce in natural flow, so the ESP system was pulled and the fluid production was maintained without any lifting system in the well. After operating for almost one year the water cut increased from 10% to 65% and the well potential decreased until it produced only gas through the tubing (Figure 1). With this conditions of high gas liquid ratio (GLR), the Operator decided not to install any artificial lift system and declare the well non-operative.

After reactivating the well, the fluid rate expected was between 400 BFPD and 700 BFPD with an API gravity of 28.9º and GOR of 6120 scf/stb. The casing size was 9-5/8" with a production tubing of 3-1/2". Because the amount of fluid expected and the casing size available, 538 Series ESP was considered the best option to produce the fluid with a high volume of gas. However, this type of pump requires 50 Hz and 8.6% of free gas at the pump intake to lift a maximum production of 725 BFPD. If the pump is operated with more free gas, there would be a high probability of gas lock and poor performance. Therefore, a preliminary stage of gas separation would be required before the fluid reached the pump intake.

The first separation stage was designed with regard to the well conditions seen prior to the shutting the well in (Table 1). The static gas separator must be connected to the system through an ESP capsule, which allows the free gas to travel up the annulus. This capsule would shroud the sensor, seal, motor, and the middle of the ESP gas separator to enable the vent holes to communicate with the casing annulus.

DESIGN GAS SEPARATION STAGES

The first stage of gas separation was designed by Odessa Separator Inc. and consists of a set of equipment located below the shrouded ESP. This set of equipment was the first entry of fluid to the ESP pump and separates the gas from the fluid using the Venturi principle in stage 1 and Centrifugal force in stage 2.

Stage 1

The design consisted of two 3-1/2" x 24' x 15 slot Tubing Screens, each functioning as an inlet for the well fluid. The fluid enters through the 304-stainless steel screen, which provides 667 in² of open area where the first stage of separation of the free gas occurs. Fluid then travels down inside the base pipe of the Tubing Screens. The coalescing phenomenon makes the gas bubbles larger, which rise due to their lower density within the "downstream" of fluid and exit through the screen of the Tubing Screen into the casing annulus. This action is illustrated in figure 2.

The next separation section is created by two 3-1/2" x 5-1/2" x 24' Gas Separator Bodies, connected in series under the Tubing Screen. The gas separator body has a design which creates a Venturi effect on the "descending torrent", the fluid flow through the 3-1/2" neck section into the 5-1/2" chamber. The separator body allows the separation of free gas in the fluid due to the change of pressure and velocity resulting from the changing diameter within the OSI Reduction Ring. This gas ascends by buoyant forces and exits the gas body through the mesh of the Tubing Screen by "gravity separation" (Figure 3). Inside the Tubing Screen and Gas Separator Bodies is an internal pipe with an O.D. of 1.90 in., called dip tube, which ends with a Helix 3.3 that is connected on the bottom of the dip tube.

Stage 2

Subsequently in stage 2 the fluid (with less free gas) is received by a Vortex Gas Separator which forces the fluid to descend in a spiral creating a centrifugal effect which finishes separating the gas (Figure 4). The liquid fluid now rises through the center of the Vortex and enters the Dip Tube for entry into the ESP.

Liquid then enters the ESP Capsule, and into the inlet of the ESP gas separator. The separator will induce centrifugal movement and turbulence in the fluid for a final separation of remaining free gas, which is through vent holes in the top ESP section. Additionally, for the success of the project and to ensure the ESP pump would not lock due to free gas, a gas handler pump (GPU) was installed above the ESP Gas Separator. This equipment pressurizes the fluid to maintain the gas in solution when fed to the ESP. In the event, any significant free gas was to remain in the fluid and ESP compression pump with mixed flow stages was installed.

The design of the selected equipment in critical to the project's success:

- The slot size of in the tubing screen maximizes total open area available for the planned production rate. The velocity should be less than the critical non-erosive velocity for the open area and production rate. (The calculation of the fluid velocity through the tubing screen is shown in Figure 5).

- The risk of having 2.2 MMCF/D inside the shroud could lock and burn the pump, so a system with sufficient gas separation capacity was essential.
- The diameter of the static gas separator will provide the required fluid velocity decrease to generate free gas separation and increase efficiency of gravity separation. In this case, because the density, a fluid velocity less than 0.44 ft./s was recommended. (Figure 6 shows the simulation of the fluid velocity inside the gas separator bodies).
- The length of the static-centrifugal gas separator is critical when allowing for sufficient agitation to generate as much gas as possible before entering to the shroud.
- The helix creating the vortex effect, must be selected to match the expected production through the system.
- The size of the ESP and volume of the shroud around it determines the velocity of fluid around the ESP motor to assure a cooling effect is achieved.

OPERATION OF THE DOWNHOLE GAS SEPARATOR

ESP pumps work by transferring kinetic energy to the fluid using high rotational velocity. The transfer of energy is proportional to the density of the fluid receiving the energy. Because of their density, liquid particles receive a large amount of kinetic energy that increases the flowing pressure. Any free gas in that enters the pump will not be able to receive the similar amount of energy because of its much lower density than the liquid. Because of these reasons the performance of centrifugal pumps always deteriorates if, along with the liquid, free gas also enters the pump. Since increasing the submergence level of the pump to a point where the PIP would be greater than the bubble point pressure was not possible the fluid would have to be treated to reduce the amount of free gas that enters into the pump.

Figure 7 illustrates the whole operation of the down hole gas separator. In this installation, the perforations will be located under the OSI Gas Separator, so the fluid will flow up from the bottom until inlet of the two Tubing Screens (Dashed lines) where the interface of the fluid with the V-wire will act as coalescing plates, forcing the gas bubbles to collide/baffle, making them larger and helping them to rise the annulus. This is the first separation of the free gas.

After the fluid enters the base pipe it flows down and enters the first gas separator body. When the fluid passes from the smaller 3-1/2 in. diameter neck through the reduction ring the fluid velocity will decrease in the 5-1/2 in. oversized body tending to separate more free gas (Venturi effect). The fluid now with less free gas flows down to the second gas separator body where the Venturi mechanism will separate more free gas. Additional gas is separated from the fluid as it falls toward the entrance of the dip tube. After this, the fluid will reach the bottom of the dip tube set inside the Vortex sleeve. The helix 3.3 installed at the end of the dip tube creates the centrifugal force and separates any remaining free gas and any solids present. The fluid then enters the dip tube and flows up until reaching the ESP Shroud.

In general, the maximum capacity of the separation tool, is determined by the volume of the gas separator bodies. This is the volume between the ID of the oversize body and the OD of the dip tube / gas anchor.

RESULTS

The downhole gas separator was installed in December 2015 in combination with the gas handler and the rotary gas separator both parts of the ESP system. The operation of these tools helped the cool motor and reduce the vibrations under 1G. At surface the fluid was delivered with some gas produced by the pressure drop along the production tubing.

Figures 8 and 9 show the sensor graphs for two periods. The graphs recorded some variations of the pump discharge and intake pressure produced by the gas in the systems, when the amount of gas overcame the capacity of the gas separation stages. Without the operation of the downhole gas separator the ESP would be locked by gas and the only fluid as surface would be gas. Additionally, the system would be subject to constant shut downs, overheating, high vibrations and underloading.

To evaluate the gas separation efficiency sonologs were used in the well, which shows a great volume of gas was being produced through the annulus while the other portion of free gas was flowing through the production tubing. Figures 10, 11 and 12 show more than 1.75 MMscf/d gas flowing through the annulus. Moreover, due to the amount of gas in the annulus the sonolog results are not the most reliable and suffered from too much noise. Based on this, the pump intake pressure was determined to be the most accurate means to evaluate and analyze system performance.

When the well shut down (due to failures in the power supply of the field) the gas supply received at the gas plant decreased around 2.2 MMscf/d, the gas production estimated for this well which represents more than 18% of the total gas production in the field.

Due to annular gas production, the efficiency and operational success of static and centrifugal gas separation equipment and their design has been demonstrated.

CONCLUSIONS

- The use of Tubing Screens combined with gas separators bodies and the vortex gas separator demonstrated to be an effective tool in ESP systems to separate free gas and allow fluid production in gassy wells with high GOR.
- It is possible to install and operate an ESP system in wells where the produced fluid has a very high GOR. This is possible using static-centrifugal gas separators often utilized commonly in Rod Lift and PCP systems installed below of the ESP in conjunction with a shrouded ESP.
- It is of utmost importance to design the first stage of free gas separation per the well conditions and fluid properties. In general, the fluid production, gas volume, API gravity, viscosity, temperature, and mechanical well conditions are the minimum to design the correct tool.
- To achieve a better efficiency in gassy wells with high GOR, the ESP design must include equipment for gas separation and gas handling in the second separation stage. Additionally, the venting points must be set above the top of the shroud to guarantee the free gas does not enter the pump intake.

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Table 1 – Well conditions

PARAMETERS	
Bottom Hole Temperature [ºF]	235
Surface Temperature [ºF]	110
API Gravity [ºAPI]	28.9
Specific Gravity of Water	0.94
Specific Gravity of Gas	0.74
Tubing Pressure [Psi] (THP)	120
Well Depth [Ft] (MD)	11454
Top of Perforations [Ft] (MD)	10884
Bottom of Perforations [Ft] (MD)	11249
Pump Depth [Ft] (MD)	8000
Inclination	63.44
GOR [scf/stb]	6119.63 (SCF/STB)
GLR [scf/stb]	3000
Bubble Pressure (PSI)	1200
Scale Tendency	Yes
Well Potential [BFPD]	700 Bfpd
- Min [BFPD]	400
- Max [BFPD]	700
- Min PIP	500
Water Cut [%]	51%
Casing Size	9-5/8”
Tubing Size	3 1/2’’

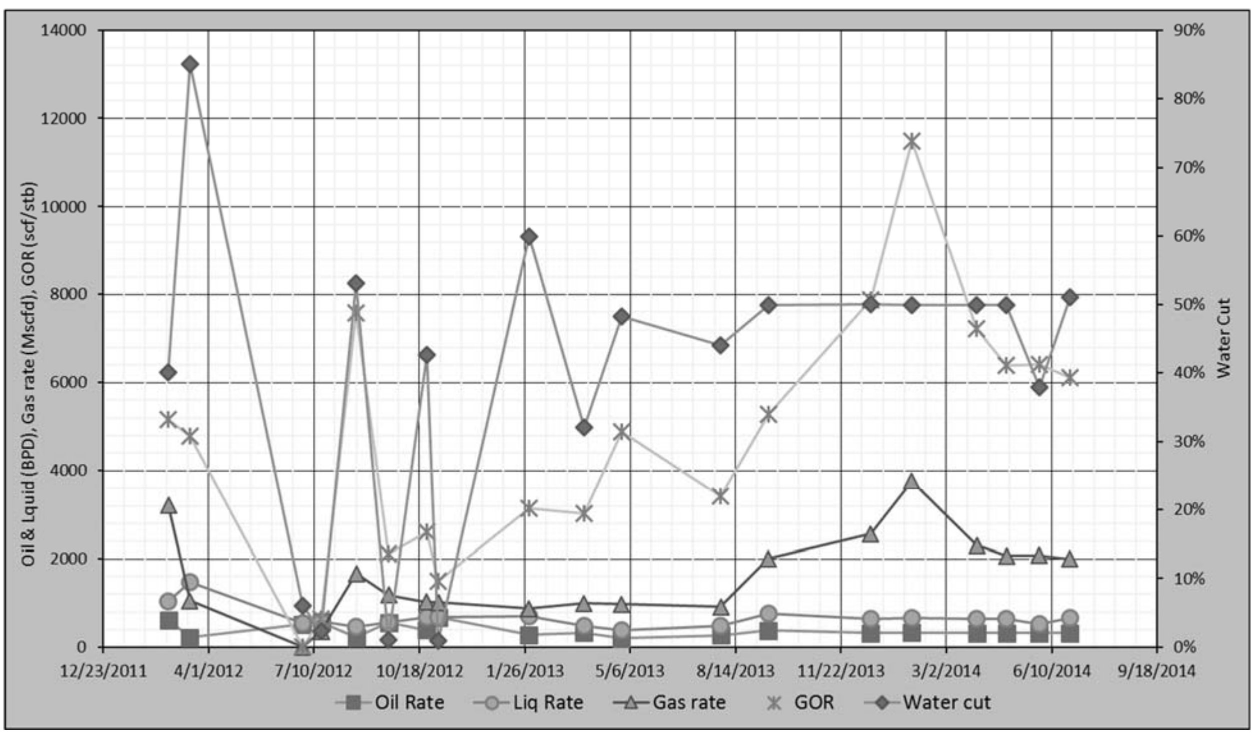


Figure 1 – Initial performance of the well

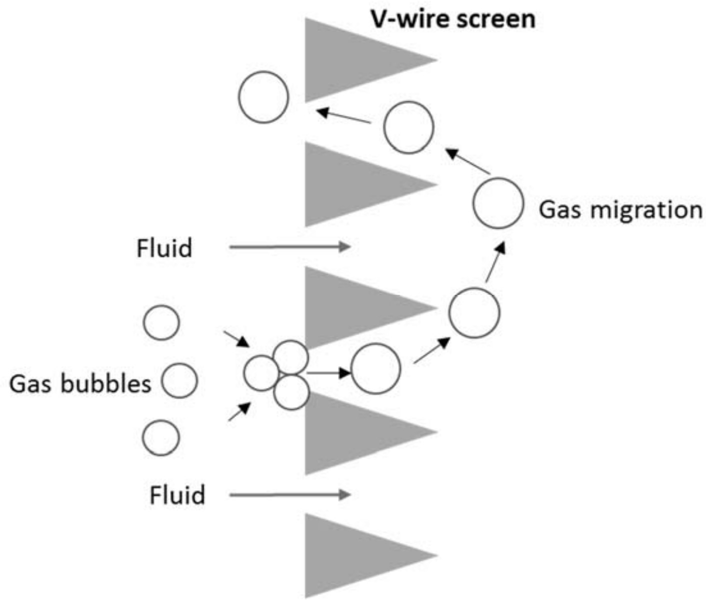


Figure 2 – Coalescence effect in the V-wire screen

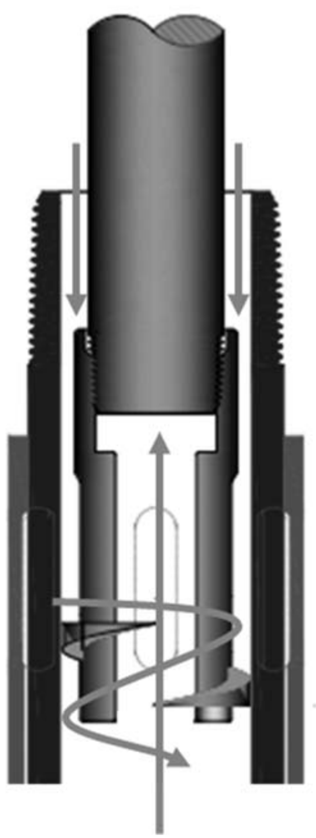


Figure 4 – Vortex Gas Separator

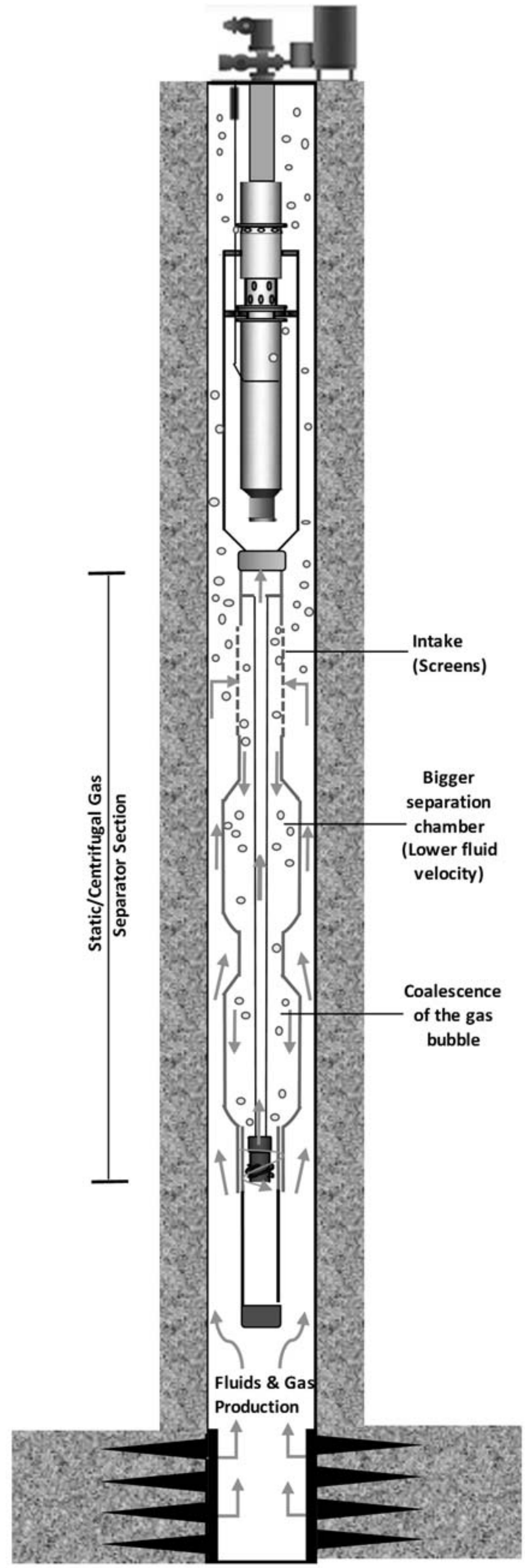
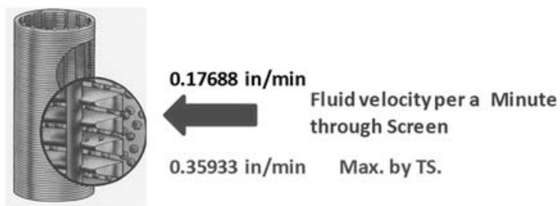


Figure 3 – Bernoulli effect in the gas separator body

TUBING SCREEN CALCULATOR		
INPUT DATA		
Production of total liquid barrel per day	700	BFPD
Percent of run time	100%	%
Selected Tubing Screen:	*3-1/2"*23.5'*	
Slot	*0.015*	
Well classification	*AVERAGE*	
Open area of screen (in^2)	333.3	
# Tubing screen	2	

CALCULATED RESULTS		
Size of Sand	50	Mesh
Total Open area of screen	666.6	in^2
1440 minute per day *%of time	1440	min/dia
production per mintue of run	0.48611111	bbl/min
production * barrle cubit inch	4716.25	in^3/min
Production inch/ by screen opening	0.17687706	in/min



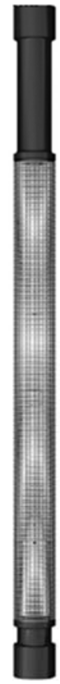


Figure 5 – Tubing screen simulation

Gas Separation Tool			
INPUT DATA			
Total production of liquid barrel per day	700	BFPD	
Casing	9 5/8	in	
OSI SIZE	3-1/2" x 5-1/2" OD	in	
API	28.9		
GOR	6120	sfc/stb	
Slot	15		
Open area "Tubing Screen"	666.6	in^2	
ID Tubing MA:	5.00	in	3.066 NECK
OD dip tube:	1.900	in	
Percentage of Run time	100%	%	

CALCULATED RESULTS		
Area mud anchors	27.02	in^2
Area dip tube	2.84	in^2
AMA (Area of the downpassage)	24.18	in^2
86400 sec per day *% of time	86400	sec/day
9702 (cubic in of a barrel * total barrels)	6791400	bbl/sec
Cubic inch per sec total cubic / by sec of run time	78.60	in^3/sec
Fluid Velocity in the dead space	0.27	ft/sec
	3.25	in/sec

For an effective separation of gas, the rate of fluid should not exceed 0.44 ft/sec or 5.28 In/sec

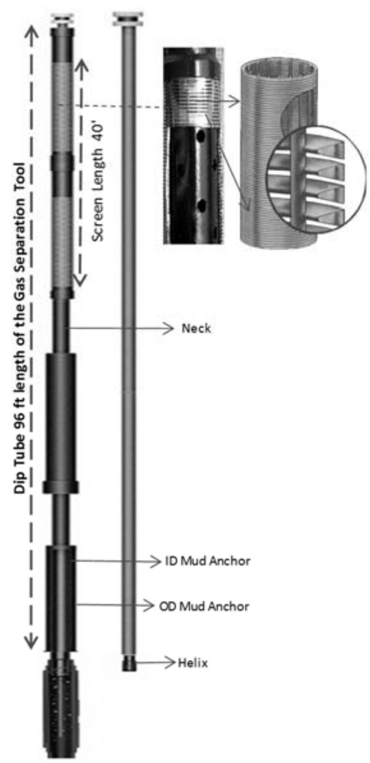


Figure 6 – Simulation of the gas separator

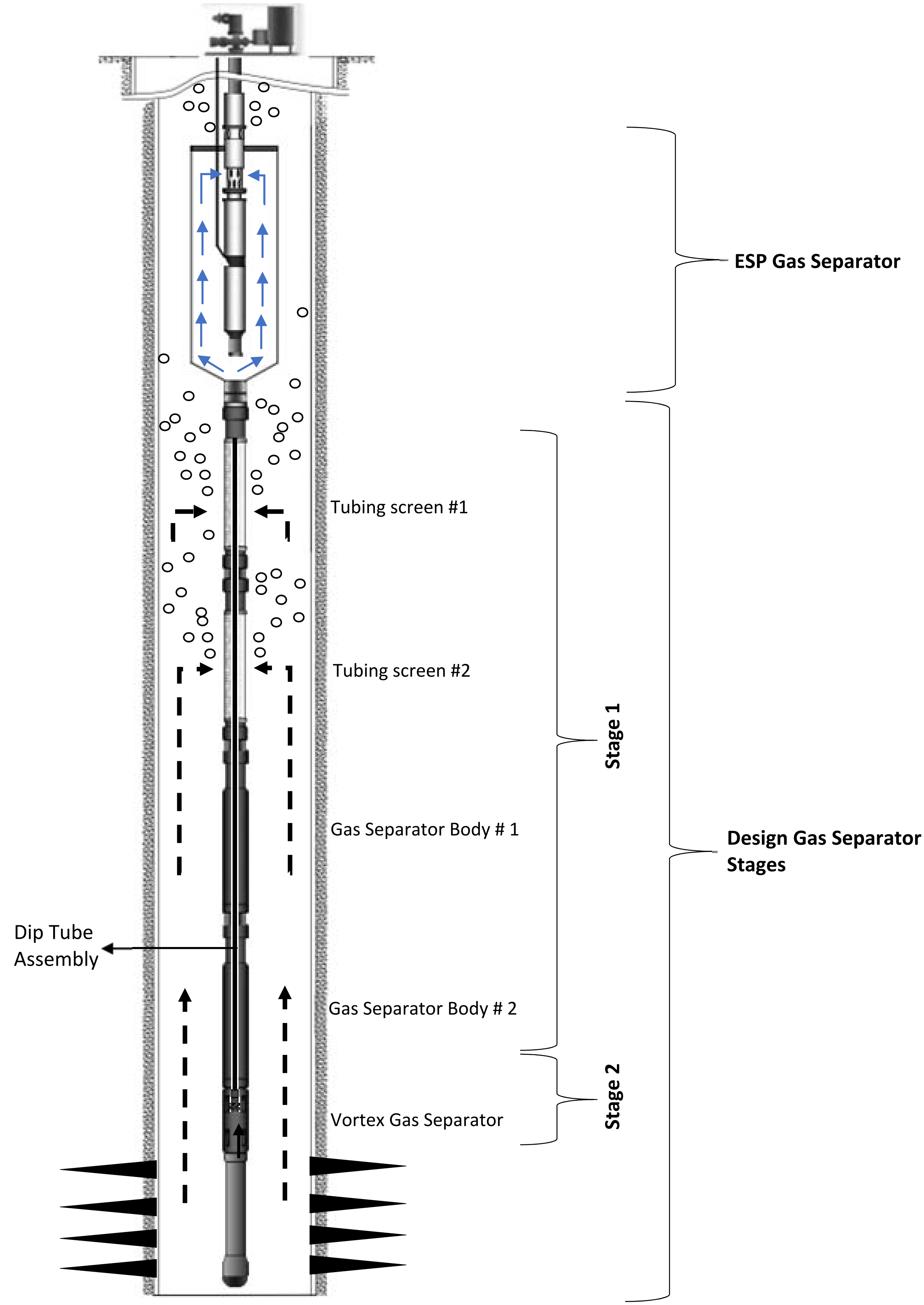


Figure 7 – BHA of the gas separator

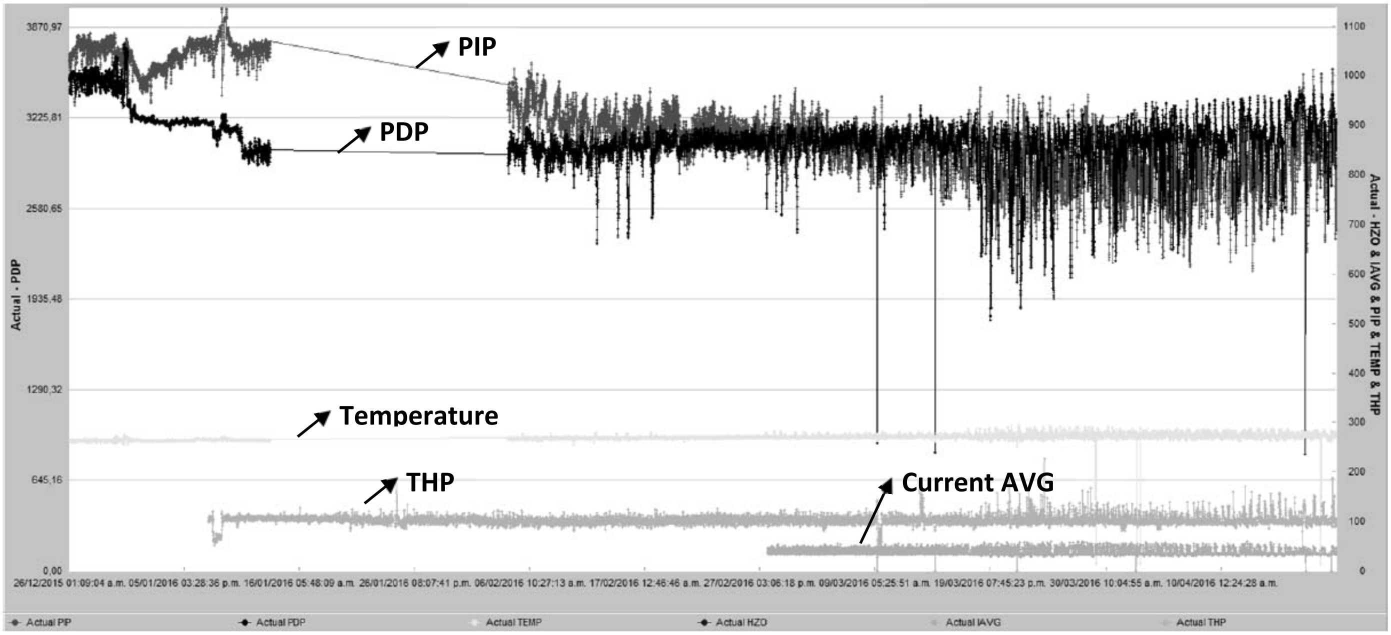


Figure 8 – Sensor graph until April 2016

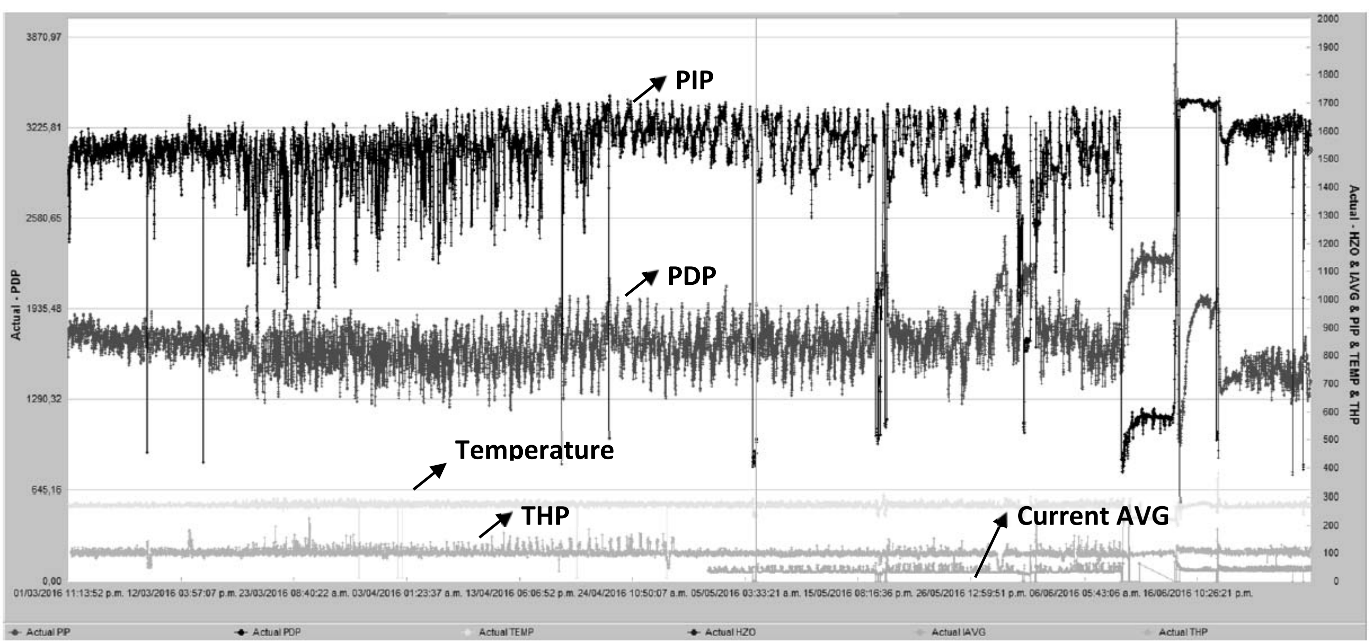


Figure 9 – Sensor graph until July 2016

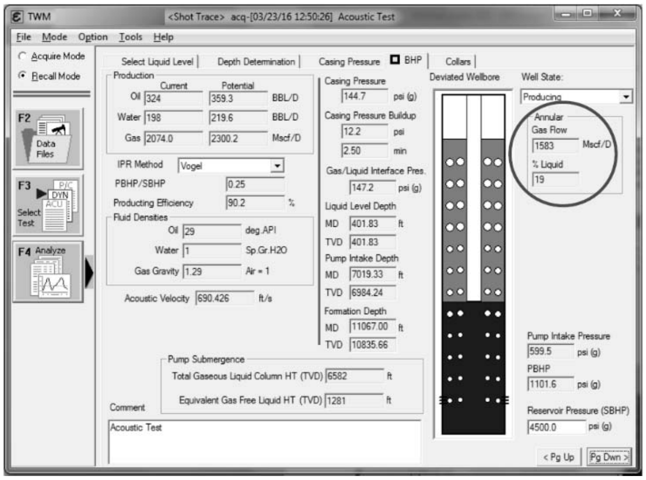


Figure 10 – Sonolog March 2016 (TWM)

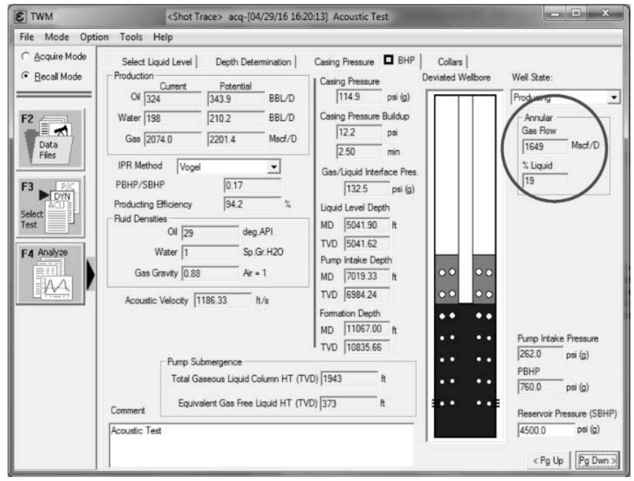


Figure 11 – Sonolog April 2016 (TWM)

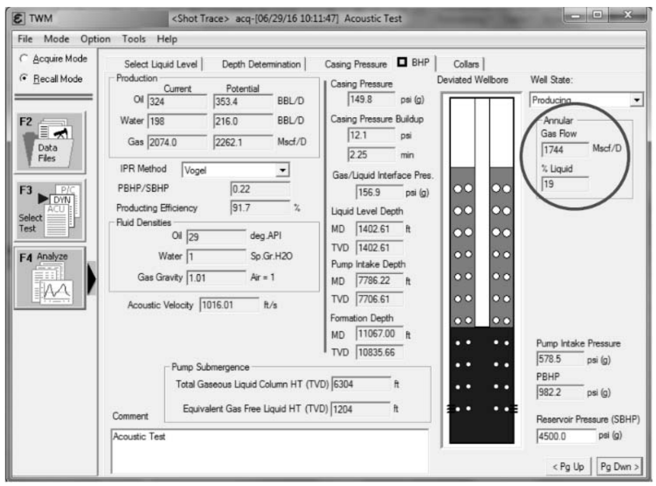


Figure 12 – Sonolog June 2016 (TWM)