SAND CONTROL METHODS TO IMPROVE ESP OPERATIONAL CONDITIONS AND RUN TIME

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ABSTRACT
Sandy wells are a common problem for any artificial lift system. Calculating the correct allowable volume of sand and solids' particle size may be the missing link in optimizing run-times and establishing solid pump performance.

Recent Colombian ESP case studies were conducted in fields with high sand/solids presence. Where run times typically lasted 5 months or less, a new design to improve ESP performance introduced a Cup Packer and screens below the ESP sensor.

Once ESP variables such as intake pressure, drive frequency, and temperature were considered, the unit conditions stabilized and improved performance followed, greatly extending run times, and reducing unnecessary intervention costs.

INTRODUCTION

Oil wells submitted to waterflooding typically show high solid production because of chemicals reactions (hydrolysis of Quartz, Carbonate reaction, etc.) and changes in the capillary pressure, which generate the sand production. These problems could be controlled using the right well completion plan (e.g. gravel packing) or monitoring the injection pressure to avoid overwhelming the hydrodynamic forces of the grains within the formation. However, the problem is usually discovered after completing the well and the production engineers must be faced with continuous failures during the well production.

In cases where sandy wells are operating through an Electric Submersible Pump (ESP), the production of fluids with abrasive solids has the most damaging effect on the pump operation. The abrasive damage caused in the ESP pump takes different forms and occurs in different places in the system. In general, the problems are severe where the abrasive particles move with high velocities. The most common wear points are:

- Erosion in the pump stage
- Abrasion in radial bearing
- Abrasion in thrust washers and thrust bearings.

Because of the large velocities, the solid particles can damage important components of the ESP pump and although, there are many solutions to prevent damage, it is common to find that the results are not as expected. For this reason, there is a need to look for the right option in each case and offer long term solutions, Odessa Separator Inc (OSI) has designed a criterion of analysis which has proven effective in recent applications using screens in standalone completions Tubing Screens). This method combines the solid size characterization with the sand rate expected in the well. This technique was successfully applied in a well, for this paper it will be named Well A, in Colombia.

WELL CONDITIONS

Well A was drilled in 2011. It was initially completed in zones C and B and recompleted in the zone A in May 2014. The well receives water injection in zone A mainly from the injector well, Well B, which was opened for injection on January 20, 2014.The current Well B injection conditions are 1189 BWPD and 4250 psi.

The well was diverted in July 2011 to the final depth of 7700 '(6890.5' TVD), reaching a maximum deviation angle of 34.50° at 6189 'MD and a maximum DLS (Dog leg Severity) of 3.19 degrees / 100 feet at 1919 'MD. Because of operational problems during drilling, two sidetracks were also made (Figure 1).
In August 2011, the zones C and B were perforated in 25 intervals between 5908 'and 7280' and the production started after the installation of the ESP.

After a run life of 958 days, the well was stopped in May of 2014 to do reconditioning work and perforate zone A. The ESP equipment was pulled out without failures and the bottom hole was clean. The well was opened for production after isolating zones C and B temporarily. At this point, the well-produced in natural flow for 2 months. In July of 2014, the well was checked again and 125 ft. of sand was found above the retrievable bridge plug. The ESP system was set up in the well at 5695 ft. (between perforations) and the zones A, B, and C were open to production.

In November of 2014, the well was serviced for power failure (Run Life = 139 days). The bottom of the hole was found at 7250 ft. (400 ft. of sand) and the pump had solid particles in the intake and throughout multiple stages. The ESP was set up at 4751 ft. (perforated top @ 4684 zone A1f) and the well was opened for production. In January 2015, the well failed (Run life = 48 days). In the operation, a deposit of sand was detected inside the tubing @ 4686 ft. (10 ft. above the discharge head). Additionally, there was a sample of sand in the pump, AGH and the upper protector as illustrated in figure 2.

Considering that after the reconditioning in zone A carried out in May 2014. Well A, began to present sediment contribution and had increased the number of interventions necessary. It was decided that detection of areas with high sand production was necessary, to identify and isolate them. The proposal for reactivation was to isolate the sandy intervals, thereby reducing the numbers of interventions and redesign the lifting system. An ESP pump with mixed flow geometry, which is recommended for sediment management, was chosen to achieve an oil production of 120 BOPD. Moreover, after the execution of this operation the well was stopped many times increasing the operative expenses of the project. Figure 3 shows the run life of the well.

DESIGN OF THE SAND CONTROL TOOL

The sand control tool was designed by analyzing the well conditions and the characteristics of the sand formation. The failure report showed a severe solid problem, which required the control of the sand before it entered the pump. Table 1 summarizes the well conditions for a medium oil flowing through the ESP system located above perforation.

A sand sample was collected and sent it to OSI's laboratory, where the sand sieve and compositional analysis were made to identify the type of sand particles affecting the system. The results are illustrated in figures 4 and 5. The sample showed 39.31% ferrous material because of the decomposition of the well pipe. The compositional analysis suggested high scale tendency due to the mineral and chlorides content of the sample (Figure 4). Figure 5 shows the sand size distribution where the 93.33% of the sample was equivalent to large solids greater than 400 microns. The sand sieve characterization showed well sorted sand but with non-uniform grains and a little amount of fine sand (2.31% by weight).

All the conditions analyzed allowed OSI to determine that the main problem in the well was coarse sand affecting the production equipment. Because this, the use of centrifugal systems was discarded because the fine sand fraction was approximately 2%. Additionally, the use of sand screens in standalone completion was not the best option because the nonuniformity of the grains, the scaling tendency, and the presence of corrosion. To solve these problems and choose the right slot size for this application, the screen was sized to be equal to the formation sand grain size at the 70th-percentile point of the sand sieve analysis. The theory is that because the presence of nonuniform sand, the larger particles will not be stopped in the opening of the screen and the bridges will not be formed for the well graded sand. The best option is to not let this coarse sand stop in the screen and to filter out the sand grains bigger than the slot size chosen. When this technique is used to control formation sand in these conditions, the diameter and length should be as large as possible to maximize the inflow area and minimize the amount of resorting that can occur. The capacity of the tool was calculated through the simulation of severe sandy conditions (sand rate > 200 mg/l) and using a safety factor of 3 (because the well was producing through an ESP). Figure 6 shows the results of the simulation made to determine the length of the tool. The minimal number of Tubing screens for this application was two but in agreement with the operator company was decided to run three even when the simulations was made it with severe conditions and a safety factor.

In determining the necessary length of the tool the critical erosion velocity, the plugging risk for the scaling tendency and oil density were important factors. The use of the ESP system needed that fluid level above the pump should be maintained constantly to prevent the pump from operating dry. The OSI Bypass valve was considered to solve this problem because it works when the filtration is no longer effective allowing the fluid to pass through the 75-slot screen and opens the valve to keep the fluid flowing through the system (Figure 7).

OPERATION OF THE SAND CONTROL TOOL

Because it was an ESP, the pump must be placed above perforations and the production zones must be isolated. The tools used was a two-cup packer installed below a Super Perf 3-1/2" x 4' x 75 slot connected with a pup joint 3-1/2" x 8'. The Super Perf was connected below the pump sensor and it would be the outlet point where the fluid would exit after passing through the filtration system (The Tubing Screens).

Below the packer, the design was composed of a Pup Joint 3-1/2" x 8' and 2 Tubing Screens 3-1/2" x 24' x 15 slot stainless steel V-wire screen (> 400 Micron). Below the Tubing Screens, a mud joint 3-1/2" x 30' was installed to string out the setup and avoid that the sand batch coming from the top of the formation (the critical zone) to impact all the Tubing screens and eroding the mesh. The third Tubing Screen 3-1/2" x 24' x 15 slot was run below the mud joint. It was the last filtration system set to allow the filtration of solids coming from the bottom of the formation.

At the bottom, the 3-1/2" Bypass Valve was installed below a mud joint. The valve opens upon reaching a 33-psi internal pressure differential to allow the fluid to pass continuously through the 75-slot mesh. The Bypass Valve attaches to the plug and is used in conjunction with the Tubing Screen to extend the run life of the pump.

The pup joints run above and below the packer were used to install centralizers to prevent buckling in the production string and prevent possible damage in the connections of the tool. The entire assembly installed in the well is shown in figure 8. The mix of fluid and sand will come from the formation and will pass through the three sections of Tubing Screens installed. The solid particles larger than 400 microns would be filtered out in the mesh and the fluid with the smallest particles (which are the smallest percentage in the sand sieve analysis) will enter through the 999 in^2 of open area. The fluid will flow up through the production string passing through the cup packer and will exit through the Super Perf 75 Slot. After this, the clean fluid will reach the pump intake entering to the production string again.

RESULTS

OSI's solid control tools were installed on October 18, 2015 and showed immediate improvements in the well performance. In the short term, the constant servicing that the well required for normal operation was reduced to zero (shown in Figure 9). With this great reduction in the number of interventions a longer run life was achieved (Average = 147 days, Current= 489 days). The continuous operation of the well is also shown in the fluid level graphic (Figure 10) where the intermittent operation increased the fluid level and the PIP (pump intake pressure) before the installation of the sand control tools. After the installation, the fluid level was maintained constantly in a specific level, helping to reduce the PIP and improving the well production.

The sensor graphics (Figures 11a and 11b) illustrate how the pump performance changed from the installation of the sand control tools. The black line in the figures represents the installation date. Figure 11a shows a high PDP (pump discharge pressure) generated by the additional loads of solids in the pump. After the installation, the PDP adopted a steady behavior with less fluctuation and normal values per the well production and pump depth. In the same way, the motor temperature exhibited high variation before the tools' installation compared with the steady behavior after the installation. The Figure 11b represents the sensor parameters which are normally affected by the solid presence in the pump. The vibration is one of the most sensitive parameters when the sand particles are flowing through the pump. Before the installation, the system was supporting high vibrations even above 5 G's conversely when the tools were set up the vibration loads were approximately zero. Similar tendencies are identifiable in the drive frequency and current. When the solids are inside the pump, the load supported by the motor increased and therefore the power required to pump the mix of sand with fluid increased, which increased the project expenses.

The improvement in pump performance increased the profitability of the project. Fewer intervention passing from 112 days off in a period of 255 days to 0 days off in a period of 489 days represents a great success in this well. The economic analysis presented by the company in November of 2016 showed the success of the installation. Table 2 summarizes the result of the analysis. The scenario analyzed was an average oil production of 80 BOPD (US $40/bls) with a periodicity of one failure every 11 months in the actual period and intervention costs of US $240,000. Comparing the period before and after the installation, the net present value was positive even considering intervention costs (to this date the well has not reported any failure). In the forecast column, the operation was simulated with a higher periodicity of failure (13 months) and the net present value was again positive after discounting the lifting cost and the intervention cost if any failure is reported in this period. In the actual economic analysis (Table 3) the periodicity of failure is 16 months, which is the current run life, and the net present value is 528,000 USD after lifting cost and intervention costs.

Finally, figure 4 analyzes the economic impact of the deferred production during the time down in the different interventions between 2014 and 2015. Because the production lost in the interventions, the project had a negative cash flow of 358,400 USD. In conclusion, with the actions taken in the Well A, the installation of sand separators and injection control showed a significant increase in the run time of the ESP equipment, going from 147 days to 489 days and currently operating.

CONCLUSIONS

The field experience demonstrated that the design of sand control tools incorporating the sand sieve analysis with the sand rate is effective criteria even when the sand is nonuniform. These criteria could be applied when the sand from the formation is poorly sorted and has high fine sand content.

The implementations of the OSI's sand control tools allowed to obtain the following results:

- Higher run life of the pump after the perforations of the sand A
- Increasing and maintaining of the production through the reduction of the PIP
- Increasing of the net present value of the project through the extension of the run life and the reduction of the interventions in the well.
- Protection of the pump component and improvement of the pump parameters

The well is still producing efficiently, achieving its potential, and increasing the cash flow of this project.

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Table 1 - Well conditions

Field:	CASABE SUR
Artificial Lift System:	ESP
Well:	Well A
DESIGN PARAMETERS	
Bottom Hole Temperature [°F]	157
Surface Temperature [°F]	95
API Gravity [°API]	23.1
Tubing Pressure [Psi] (THP)	85-100
Well Depth [Ft] (MD)	7650
Top of Perforations [Ft] (MD)	4684
Bottom of Perforations [Ft] (MD)	7280
Pump Depth [Ft] (MD)	4500
Desviation	33.46
GOR [scf/stb]	200
Well Potential [BFPD]	180
Water Cut [%]	38
Production Casing	7”, 29#,
Production Tubing	3 1/2’’
FLOW RANGES OF THE PUMP OPERATION	
Min [BFPD]	150
Max [BFPD]	220

Table 2 - Economic analysis

		Oil (Bls)	Income (KUSD)	Lifting Cost (KUSD)	Net revenue KUSD
2015	October	723	$ 29	$ 12	$ 17
	November	4782	$ 191	$ 77	$ 114
	December	3539	$ 142	$ 57	$ 85
2016	January	3683	$ 147	$ 59	$ 88
	Febraury	3665	$ 147	$ 59	$ 88
	March	3086	$ 123	$ 49	$ 74
	April	2367	$ 95	$ 38	$ 57
	May	2266	$ 91	$ 36	$ 55
	June	3189	$ 128	$ 51	$ 77
	July	2685	$ 107	$ 43	$ 64
	August	2609	$ 104	$ 42	$ 62
			$ 1,304		**$ 625**

	Before	Current	Forecast
Intervention cost (KUSD)	$ 220	$ 240	$ 240
Periodicity of failure (months)	5	11	13
NPV (KUSD)	-$ 28	$ 182	$ 259
Pay Back (months)	6	6	6

Table 3 - Actual economic analysis

	Before	Current
Intervention cost (KUSD)	$ 220	$ 240
Periodicity of failure (months)	5	16
NPV (KUSD)	-$ 28	$ 528
Pay Back (months)	6	6

Table 4 - Economic impact of the deferred

# OF EVENTS	STOP DATE	START DATE	INTERVENTION REASON	RUN TIME(Days)	DOWN TIME(Days)	CUMULATIVE DEFERRED (Bbls)	DEFERRED (USD$)
1		Jul-13-14	Reperforations				
2	Nov-17-14	Nov-30-14	Power cable broke	127	13	1040	$ 41.600
3	Ene-18-15	Ene-19-15	Flushing, Gas lock	49	1	80	$ 3.200
4	Ene-22-15	Ene-23-15	Bottom hole sand simple	3	1	80	$ 3.200
5	Feb-22-15	Mar-5-15	Sand cleaning, pump change	30	11	880	$ 35.200
6	Jul-14-15	Jul-15-15	Pulsing, ok	131	1	80	$ 3.200
7	Jul-19-15	Jul-20-15	Flushing, ok	4	1	80	$ 3.200
8	Jul-24-15	Jul-25-15	Pulsing, ok	4	1	80	$ 3.200
9	Jul-26-15	Jul-27-15	Pulsing, ok	1	1	80	$ 3.200
10	Jul-30-15	Oct-20-15	Sand cleaning, pump change	3	82	6560	$ 262.400
				TOTAL:	112	8960	$ 358.400

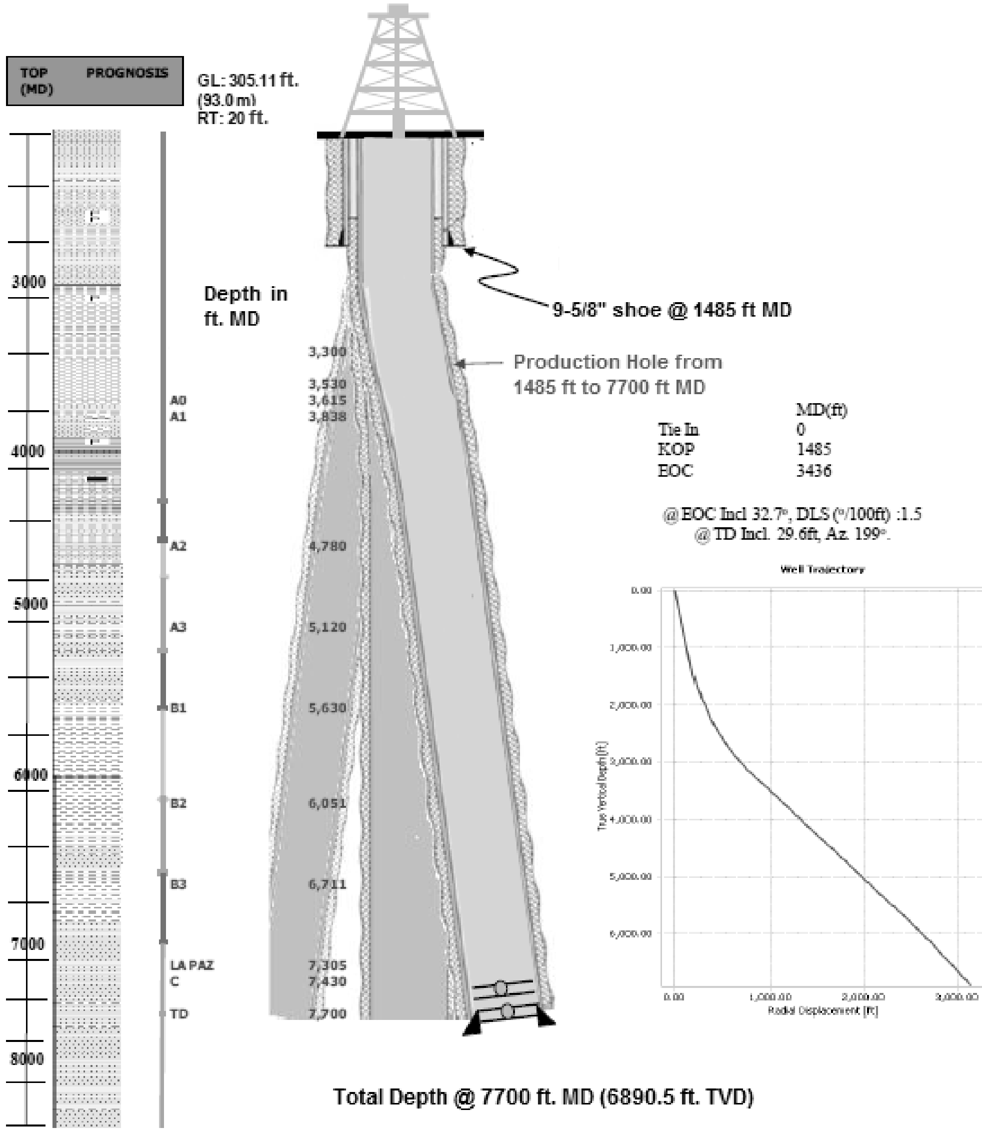

Figure 1 - Mechanical well conditions – Well A

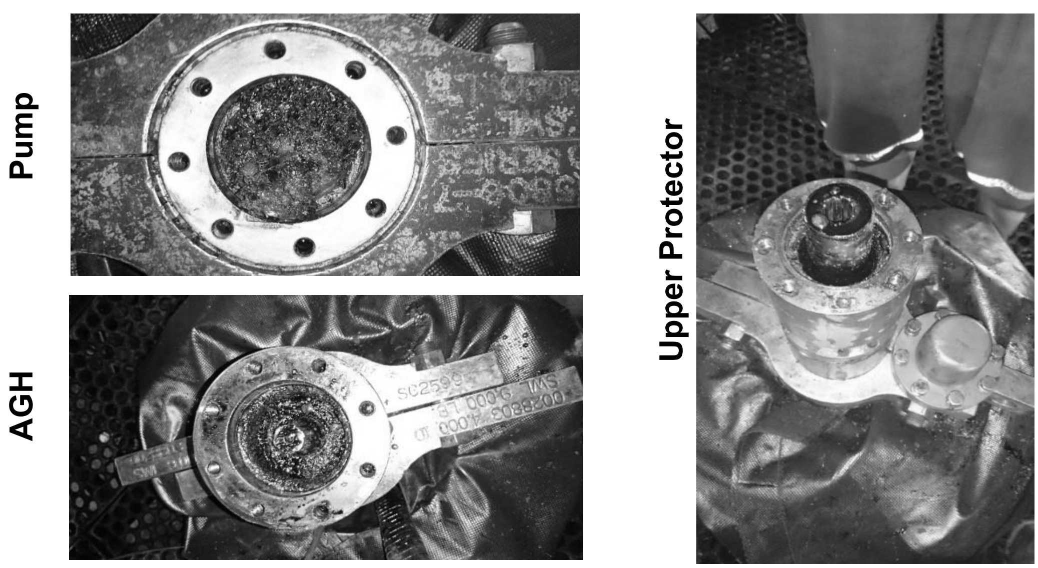

Figure 2 - ESP Conditions in the pulling - February 2015

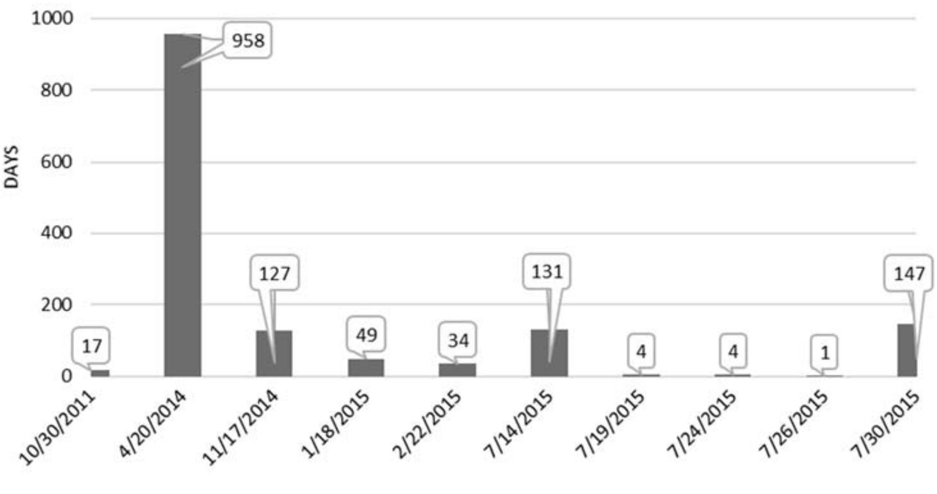

Figure 3 - Run life – Well A

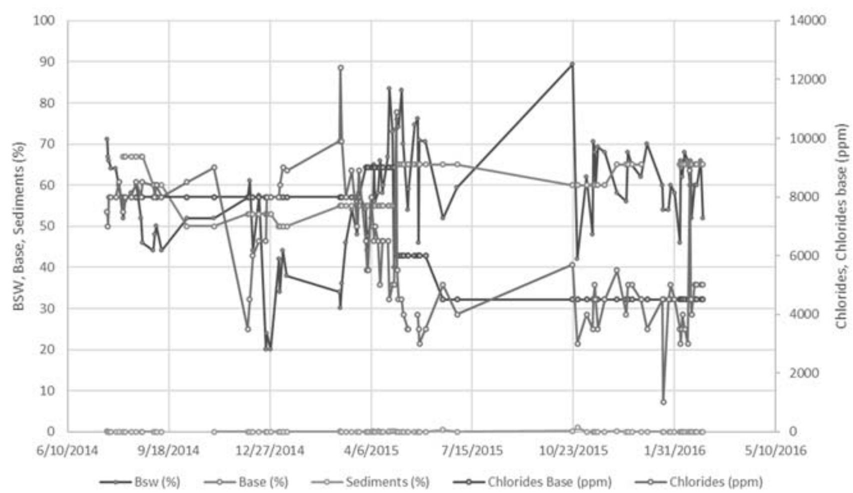

Figure 4 - Sediments analysis

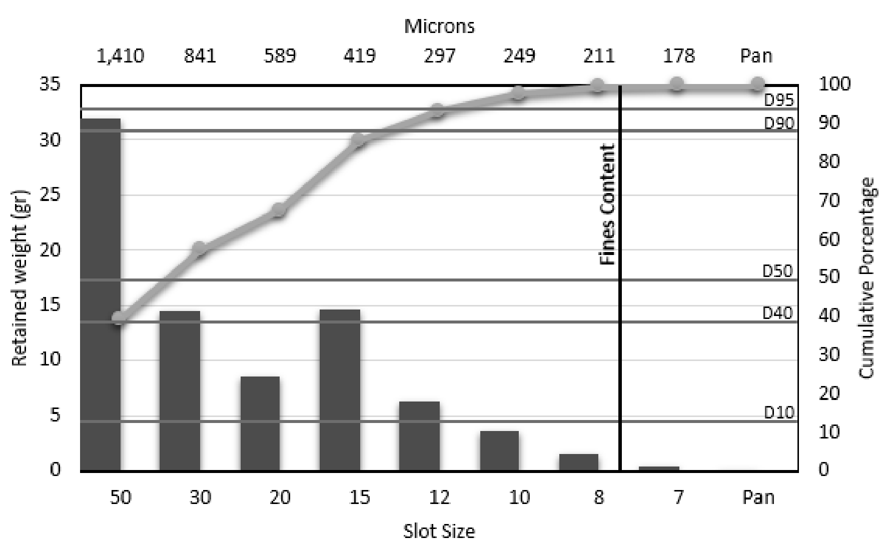

Figure 5 - Sand sieve and compositional analysis

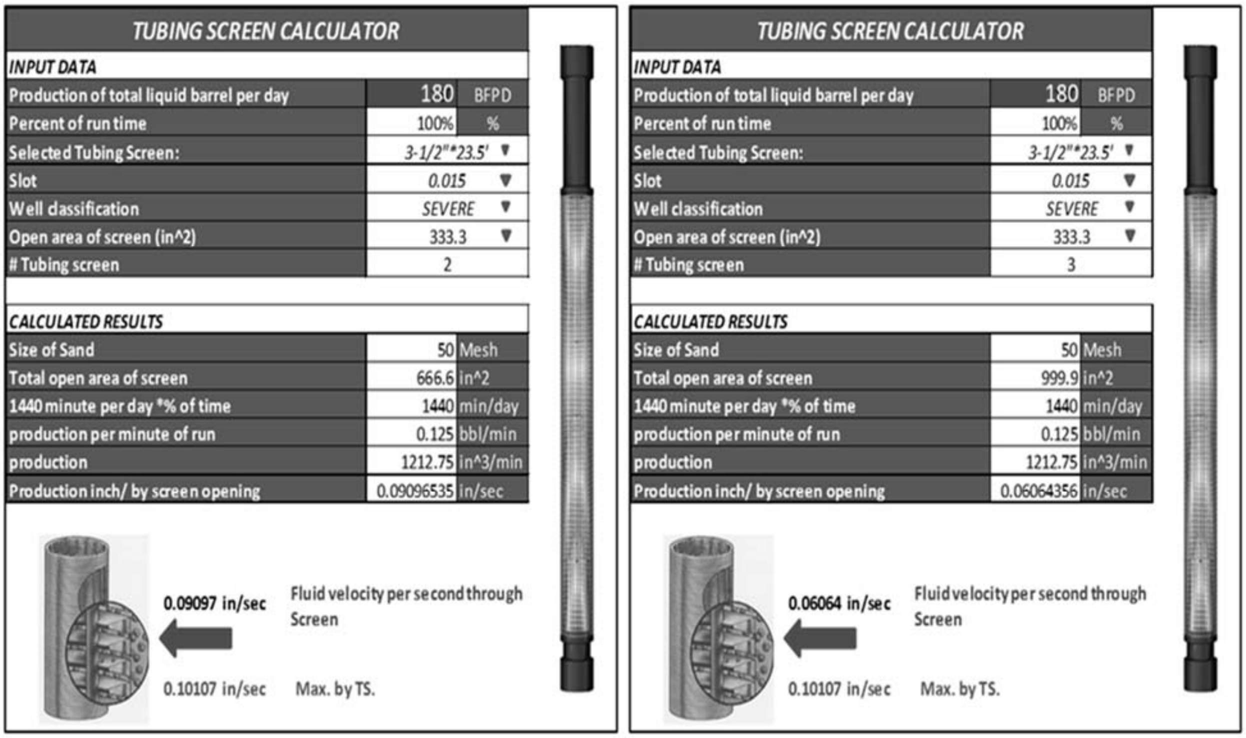

Figure 6 - Tubing screen simulation

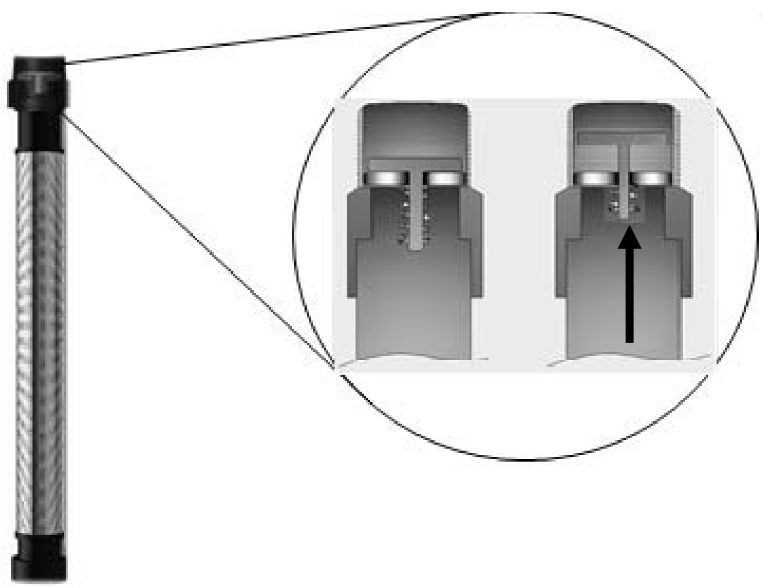

Figure 7 - Bypass Valve

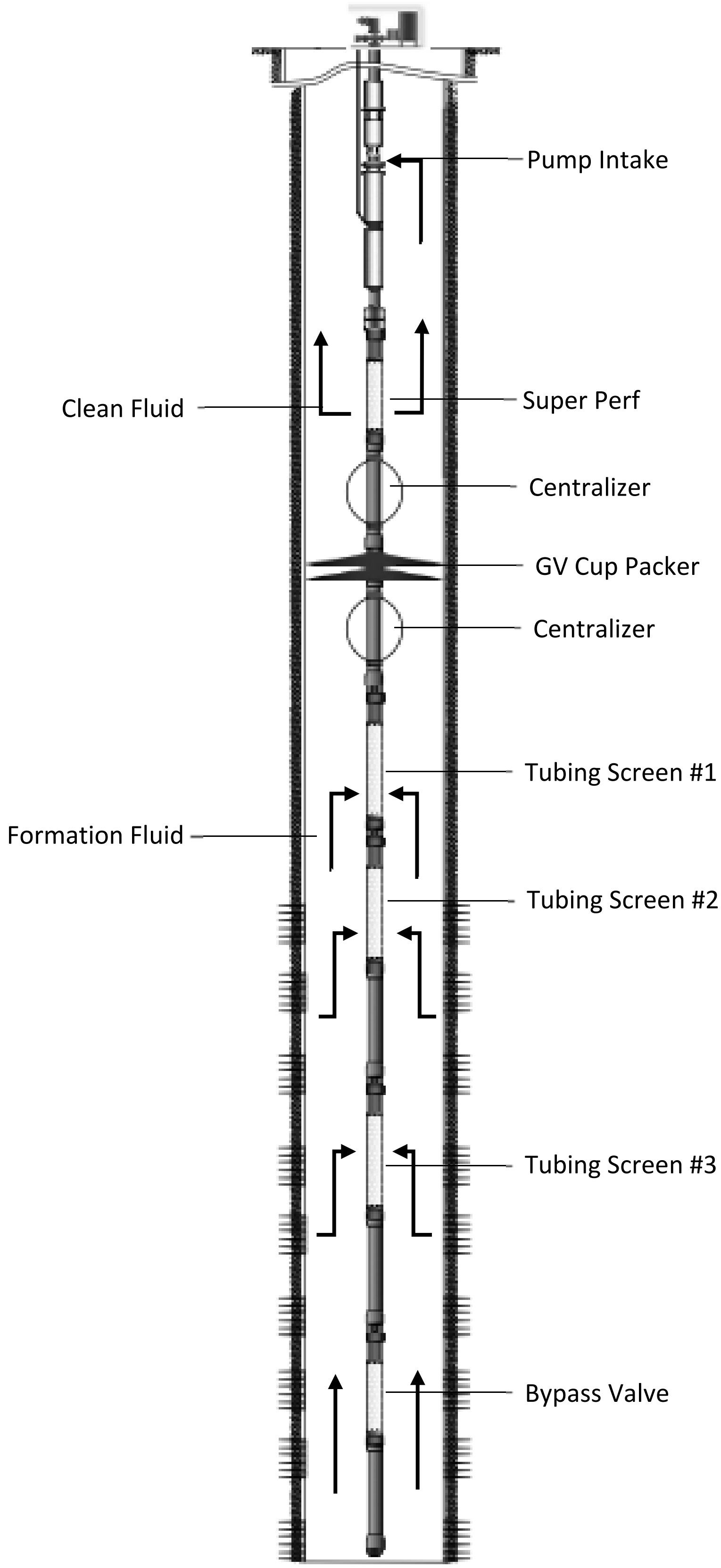

Figure 8 - OSI's tools assembly

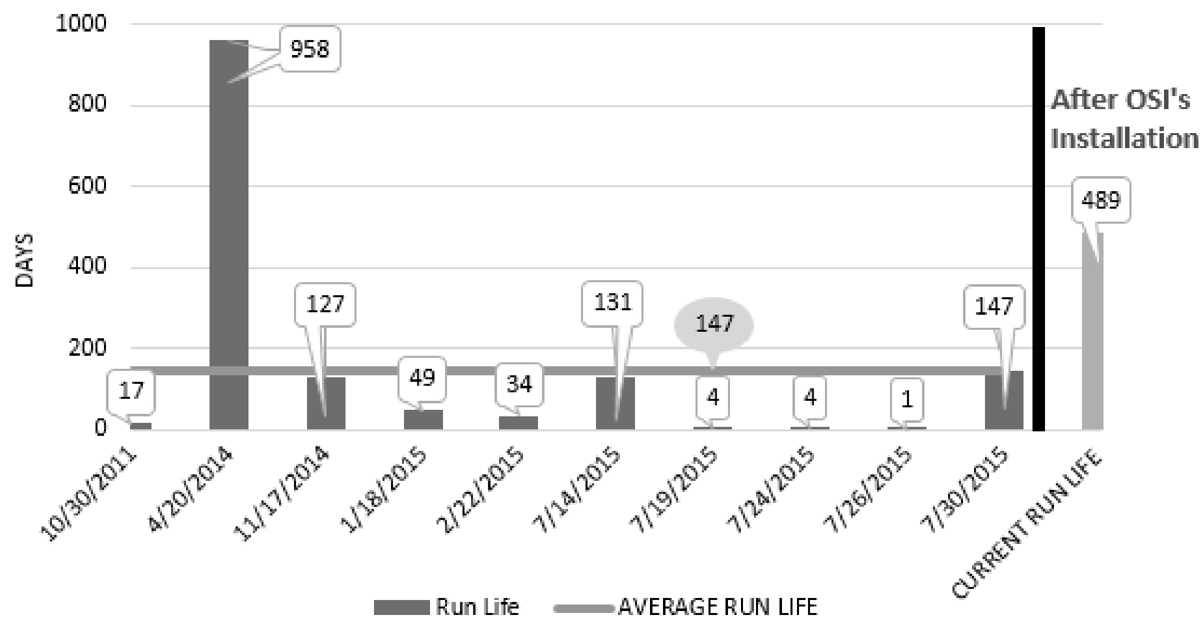

Figure 9 - Run life after the installation of the OSI's solid control tools

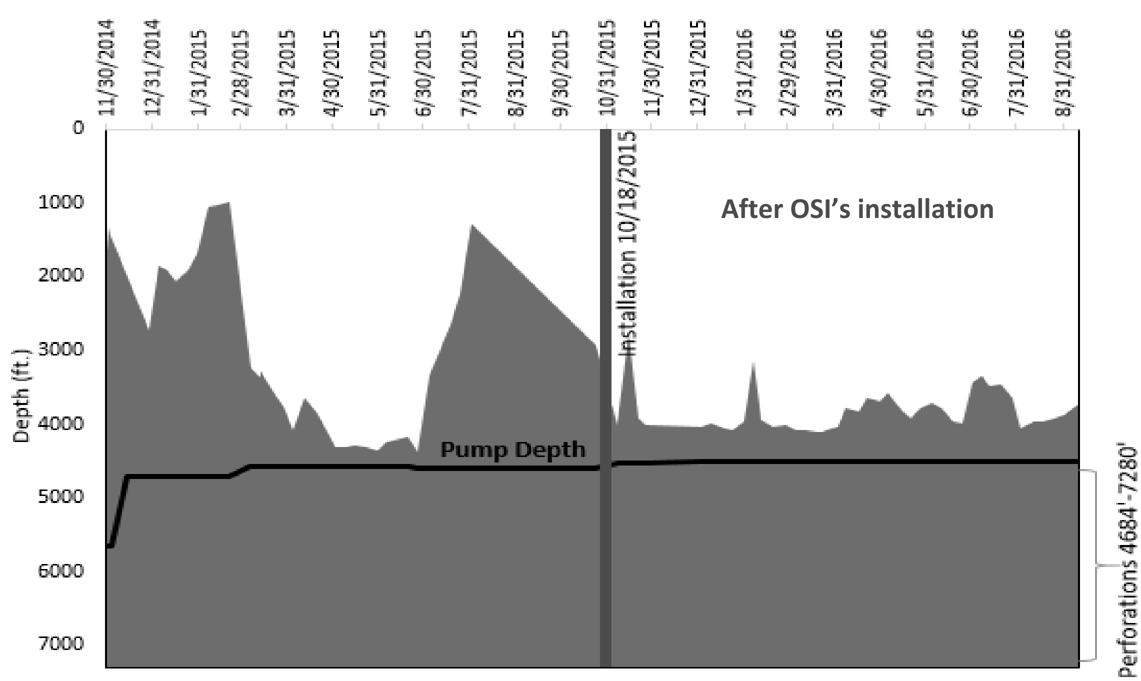

Figure 10 - Historical fluid level – Well A

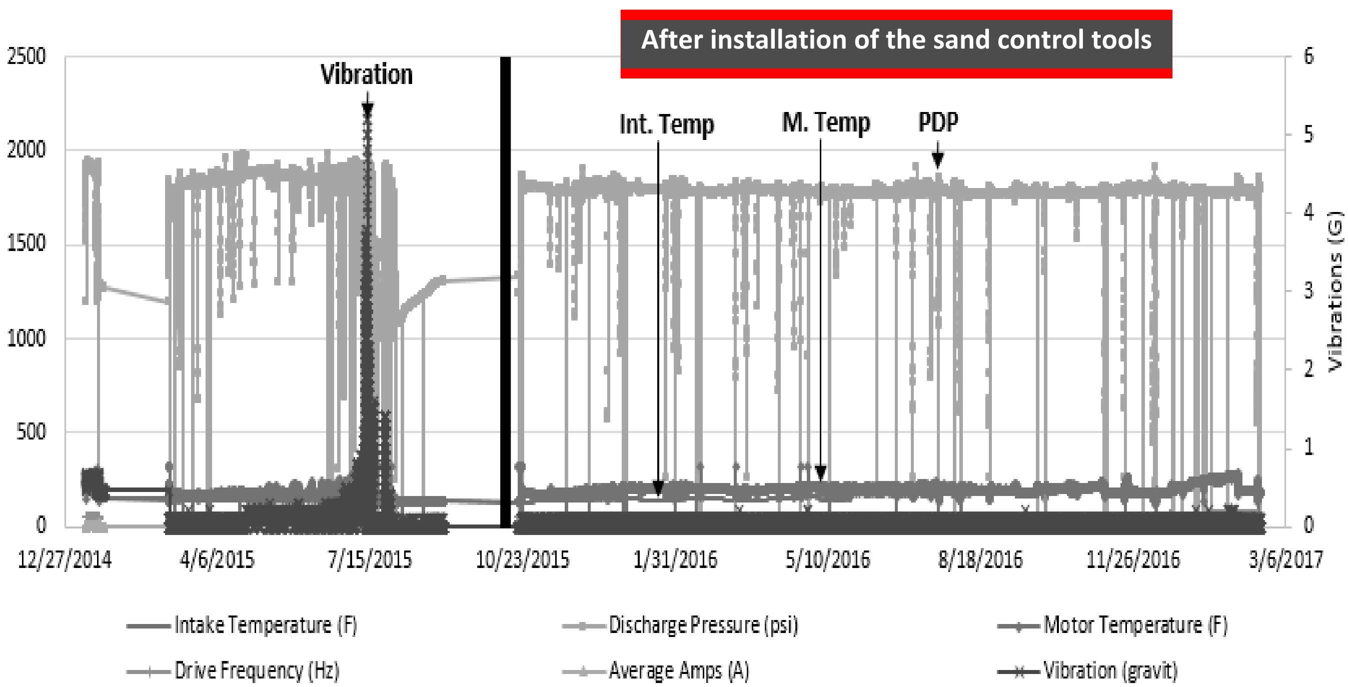

Figure 11a - Parameters of ESP sensor

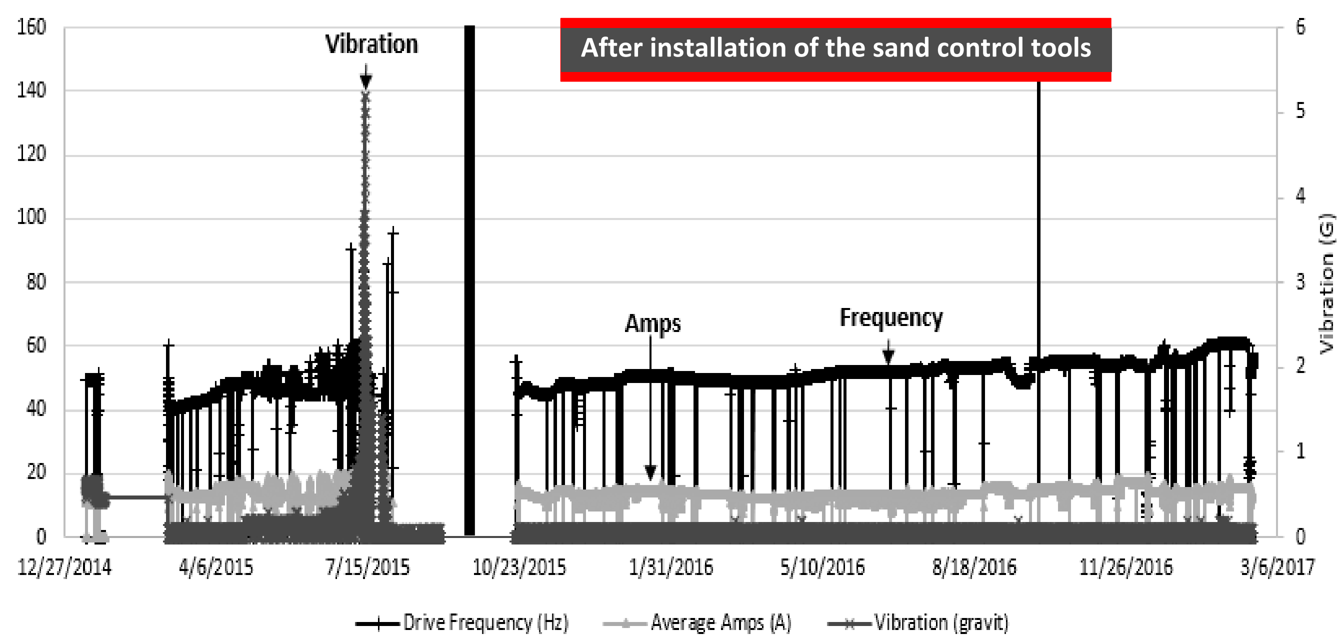

Figure 11b - Parameters of ESP sensor