SAND CONTROL MANAGEMENT IN ESP CASE STUDIES DELAWARE BASIN

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ABSTRACT

This paper summarizes the installation of 12 wells with the ESP Two-Stages Sand control system on the Delaware basin showing evaluation parameters and performance indicators. The initial stage of this project was to evaluate failure root cause that may affect the runtime of the wells, finding sand production as the main issue in this field. Based on this information, the operator started looking for solutions to avoid failure issues such as pump wear, broken shaft, pump stages plugged, high vibration, etc. The Two-Stages Filtration System was chosen to deal with the sand problems. To design the Two-Stages filtration system, it was necessary to evaluate and identify the sand particle distribution to select the total open area for the 1st separation stage and the size for the vortex desander (2nd separation stage). Chemical issues were identified by using Complete water analysis to confirm Screened intake open area and/or implement chemical solutions to avoid future complications. The methodology for the evaluation and selection of sand control systems was proven in a field with historical low run times due to sand problems in the ESPs. The methodology is explained with the theoretical concepts and through several case studies at the Delaware Basin. The project was qualified as a success achieving runtimes from 450 days to 810 days, other failures are related to electric issues and interventions due to downsizing the pumps.

INTRODUCTION

Sand control has become one of the most critical aspects when designing pump assemblies in the Delaware Basin with . Multiple shutdowns and excessive wear on the ESP components affect tremendously the OPEX of operator companies producing from fractured wells and sandy formations. Whether an oil project is viable or not may be defined for the different sand control options in the market, especially in wells with high flow rates where the ESP is mandatory. The project evaluation becomes more challenging due to the short runtimes and different investment opportunities.

High sand production will cause damages in the ESP system, when this enters the pump, causes problem such as wearing the pump stages, creating excessive vibration, then leading to damage in the mechanical seal. This type of damage could create a path that will allow the fluid to flow through the seals into the dielectric oil causing a failure of the entire system. The erosive nature of the sand will affect the impeller vanes affecting the hydraulic capacity of the pump, this would increase the clearance on the stages triggering more recirculation and ending up in a lower pump efficiency, which will increase the lifting cost. It is important to highlight that if there is a shutdown and there is sand inside the production tubing and pump, the pumps stages can get plugged and the ESP wouldn't be able to restart normal operation and in extreme cases break the motor shaft.

When the sand problems, high volume of fluid and severe chemical issues are present the use of different technologies is limited and the options are not widely available, and some solutions could pauperize the pump operation. This research presents a solution to high sand production using a combination of sand screen application and a centrifugal/Vortex generator, highlighting the big role that plays the right selection of slot size based on the size particle distribution acquired from the sieve analysis.

SAND CONTROL TECHNOLOGY – TWO-STAGES FILTRATION SYSTEM

The 2-Stages Filtration Technology provides a robust sand separation mechanism that allows to deal with the sand in different stages, the first step breaks the sand slugs (large accumulations of sand flowing at once can overwhelm any system causing low separation efficiencies) and serve as the intake of the complete system. The biggest particles are filtered out letting only smaller particles to flow through the screen where the particles will be separated by the Centrifugal/Vortex generator which we will call it as the second stage of separation for this document.

First Stage Filtration: The sand screen device is made up of a screen jacket that is placed over perforated tubing with EUE thread with a different diameter option such as 2-3/8”, 2-7/8”, 3-1/2”, and 4-1/2” as shown in figure 1. The screen section comprises a tubing screened in V manufactured on 304-stainless steel mesh where the fluid enters though the open area that has a specific design to prevent plugging in the screen. The tool capacity depends on the slot size, diameter, and total length of the assembly, in general increasing any of these parameters will increase the total open area. Table 1.

Second Stage Filtration: The second stage correspond to a Vortex separator that oversees separating the fine particles that can pass through the screen. The helix configuration generates a vortex effect which basically represents several radial forces that push the fine sand particles against the wall of the tool and by gravity these particles fall into the mud joints installed below the tool, the clean fluid flows upwards using a dip tube which intake is the same helix. It is important to calculate the right amount of mud joints based on the sand rate to avoid premature failures. The magnitude of the vortex effect is determined by the jetting area, the differential pressure, and the amount of fluid (Showed in figure 2), multiple configurations are made to adjust to different ranges of fluid production. Figure 3 shows a schematic of how the assembly looks installed.

The Seal mechanism (Cup Packer): For this application on ESP, the Sand control BHA must have a Sealing mechanism, this sealing mechanism is necessary to force the fluid to go through the sand control system. There are many options in the market including mechanical packer and shrouds, however, the technology includes an OSI Cup Packer, this packer is made out and relies only on the elastomer properties to expand and seal the casing annulus. Different materials are used to deal with different downhole conditions including high temperatures, high pressure, H_2S content or possible acid treatments in future days after the sand control system has been installed, there are different geometries possible including cups facing up, cups facing down, triple seal cup packer and more. See cup packers design figure 4.

Second intake (activation required): The dual sand separation system includes a backup solution when the intake gets plugged (tail joints full of sand) by either severe sand accumulation or combination of sand and inorganic and/or organic precipitation, allowing a continuous flow of fluid to the pump. This device goes connected right below the sealing mechanism (Cup Packer) and it has a pressure valve that activates when the primary intake open area has been reduce to a level where pressure on the valve reach 33 psi, once this condition has been met the valve is activated and a 75 Slot 4’-long screen section (Figure 5) allows normal flow to the pump. This solution provides great advantages in terms of run life however once the valve is activated the entire sand control system is bypassed and sand will flow into the pump stages.

Additional components: There are some additional components that are a required such as the (1) outlet port (Slotted sub), where the clean fluid exits the sand control system and then flows into the ESP. Centralizers are also used commonly in unconventional wells, where the Sand control BHA can or will be installed at some point on relatively high inclination or the tail pipe assembly below the vortex separator will be under a high inclination angle which may push the ESP to one side putting in risk the integrity of the pump, these centralizers maintain the ESP far from the casing walls and secure a proper packer fit because it maintains the tubing string centralized.

To design the 2-Stages Filtration System, there is some important data that is needed to analyze the whole scenario and provide the right design and recommendations. Table 2 shows the main information that it is required along another crucial such as deviation survey, previous interventions information, water analysis whether the well has or not possibilities of deposition of scale, etc.

FIELD BACKGROUND

The field is located on the Delaware basin, most specific on the Reeves County in Texas. This field has a history of failures due to sand and others a combination of sand and chemical issues. Among the 12 wells analyzed in this document 3 wells were combined with a downhole chemical treatment focused on scale/corrosion.

DESIGN OF THE TWO-STAGES FILTRATION SYSTEM

The design of each well was done individually to analyze specific points such as expected production, water cut, well deviation, installation depth and the type of chemical problem affecting the well, however, at the beginning of the massive installation project, a characterization of the field was carried out to identify the granulometric distribution on the field and the types of chemical problems. Additionally, the scenarios were analyzed, focusing on the highest production expected and chemical conditions to define the most viable method of installing the system as a one assembly. The considerations are summarized below.

First and second stage of separation:
When designing the two stages, the maximum production range must be considered but it does not have to be exact, the sand control system explained on this document provides a security factor that allows the system to work under values above the operation ranges; for example in new wells with ESP, the initial production is higher than expected so it is normal that the fluid production reaches high velocities through the screen section (1st separation section) or/and the vortex generator (centrifugal separator) delivering high separation efficiencies (theoretically above 100%). Usually, the helix size is replaced when the ESP is replaced to guarantee high separation efficiencies during the whole period.

When selecting the Slot size, identify the frac sand used is priority specially on new installations, this will provide an idea of the slot size needed and will help to determine what percentage will be separated by the first stage and the second stage, what percentage will be filtrated by the agglomeration principle on the first stage and what percentage will be flowing into the pump stages, which depends on ESP design and ESP manufacturer considerations. In many scenarios reducing the amount of sand passing through the pump stages is better than trying to separate all the sand because it can cause plugging issues on the sand control system. Knowing the amount of sand being produced is possible to design the number of tail joints required to achieve a specific run time.

Chemical issues:
It is crucial to consider organic or/and inorganic precipitation when designing a sand control system because of the effect in the total open area of the first separation stage. In cases where the sand control system will be complemented with surface chemical injection or downhole chemical application the slot size can be optimize to a smaller size allowing a greater % of separation on the 1st stage, however, if the field is known for severe organic or inorganic precipitation is recommended to install bigger slot sizes to prevent pugging issues. It has been proven that a combination of sand and chemical control is highly recommended and has achieved great results in terms of BHA integrity and runtime.
A thermodynamic simulation will offer an idea of the likely and severity of inorganic issues downhole. Based on the amount of scale determine by the simulation and the percentage of sand separated in the first stage it can be decide the right slot size.

Number of tail pipes:
When installing on new ESP wells it is recommended to run a considerably high number of mud joints because it is expected a large amount of sand coming from the frac job, based on experience and data of amount of sand vs frac sand used vs total fluid expected a number of 8 to 12 mud joints (2-7/8" assembly) has provided great results in terms of runtime. In cases where production has stabilized, the number of mud joints can be less considering the severity of the sand production. If for some reason the number of mud joints result insufficient the sand storage will reach the level to plug the Vortex separator intake which

will cause an increase in pressure on the sand control system activating the secondary intake system allowing the pump to operate normally.

CASE STUDIES

For all case studies presented in this paper, the information on Table 2 was used to design the Two-Stages Filtration System.

Based on the information provided by the operator including expected fluid production, wellbore sketch, Frac sand size, chemical issues, pump depth, inclination, previous runtime (if not a new well) information of previous interventions, etc. a slot of 15 was selected for all the wells. Depending on the fluid production, the number of tubing screens change from well to well, additionally in wells where there was evidence of scale issues, the length of screens was longer with aiming to increase the total open area to decrease the risk of plugging issues due to scale precipitation. When designing the total number of Sand Screens the maximum velocity evaluated to reduce erosion and plugging issues is 0.1996 in/sec, Table 3 shows all velocities evaluations for each well, Wells 2, 9, 10, 11 and 12 present values that surpass the maximum velocities permitted, this decision was made assuming the declination in 3 months would be 45 to 55 % which will reduce the fluid velocity to levels below maximum velocity (0.1996 in/sec). It is important to mention the risk analysis plays an important role in this type of application, this must consider also that higher production can be expected, that the well might produces less than expected, the well might deplete in a longer period or in a shorter period, however, install Sand screens with an open area resulting in a velocity above maximum recommended limit increases plugging and erosion risks.

The 15 slot Tubing screen provides a filtration capacity to separate particles greater than 381 Microns, particles smaller than this will be separated by the Vortex Desander (Centrifugal generator).

Table 4 contains the design selected for each of the 12 wells group evaluated on this paper, it shows the total number of sand screens and open area of the total assembly, the Helix size selected for the vortex generator for each well based on production expected focusing on maintaining a separation efficiency greater or equal to 60% up to 1 year of operation. Additionally, three wells were installed with a downhole chemical configuration with scale-based treatment to reduce risk of open area. The chemical treatment configuration includes a special formulation of scale inhibitor and acid surfactant to dissolve scale formed. This document will not explain this chemical technology deeply, it is just an accessory to achieve longer runtimes due to wellbore conditions.

RESULTS

In terms of fluid velocity 3 wells that by the second month presented velocities above the maximum recommended in this technology, Wells 9, 11 and 12 presented high velocities values up to the six first months and then their values dropped to velocities between 1,9 and 1.0 in/sec (Figure 6). The rest of wells maintain velocities below the maximum velocity recommended. This difference in velocity can but not mandatory affect the total open area, even though a certain amount of sand is expected, levels of sand production can vary, all wells in question last more than 360 days, being Well 12 achieving the max runtime of 810 days, however Well 9 had the shorter runtime of the well group. It is very difficult to precisely evaluate how severe a sand production will be in the first installation.

For all 12 wells production monitoring WC was considered constant due to limitations in terms of data acquisition, in this case there is no significant affectation because crude API of all 12 wells is above 38º, if application is to be used on heavy oil it is imperative to correlate the WC through the installation.

Figure 7 shows fluid behavior of well 1 which is shows a clear declination over time, this trend was considered in the design of each sand control design.

Figure 8 shows the comparison between the total fluid and the Vortex generator (2nd separation stage) separation efficiency showing a direct relationship between the production declination and the vortex efficiency, each helix size (2.6,2.7,2.8 or 2.9) have different designs that allows different fluid ranges to achieve and maintain higher separation efficiencies. Figures 9 and 10 summarizes the results of all wells installed with this sand control system.

CONCLUSIONS

- All wells achieved a runtime longer than 360 days proving high efficiency of separation. The Maximum runtime achieved on this project was 810 days.

- The minimum efficiency values evaluated by the Vortex generator designed was about 59% evaluated at 13 months after the installation.

- It is essential to consider a security factor/ security risk when dealing with new wells where production expectancy can be higher or lower than real results, this factor is applied on the number of sand screens designs and helix sizes for the vortex generator.

- Fluid velocities above maximum velocity limit for long periods can affect severity on the integrity of the sand screens.

- Vortex Generator proves that can hold efficiencies above 100%, meaning deals with strong centrifugal forces, however it is important to consider declination rate to maintain efficacy values above 58%.

- When dealing with scale issues and it is planned to install an ESP sand control system such as the one explained on this document it is recommended to complement the sand control BHA with a downhole chemical treatment or a surface treatment.

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Table 1 Different open areas according to the slot size

Tubing Screen x 1 Unit Open area					
2-3/8"		2-7/8"		3-1/2"	
Slot	Total open Area (in2)	Slot	Total open Area (in2)	Slot	Total open Area (in2)
12	254.4	12	298.7	12	349.3
15	308.9	15	362.8	15	424.16
20	393.24	20	461.75	20	539.85
50	772.44	50	907	50	1060.4
75	983.1	75	1154.34	75	1349.63

Table 2 Well Conditions-Information required to use two stages filtration system.

Well	Min Fluid Production, BFPD (EXPECTED)	Max Fluid Production Design ,BFPD (EXPECTED)	GAS RATE, MCFPD	GOR	GLR	WC	CASING	PIP (psi)	IP	Pump Depth	OSI BHA Instalation inclination
Well 1	1000	1500	750	1471	500	66%	7 32#	2552	0.806	9700	0.30º - 50º
Well 2	3200	4500	1350	3000	300	90%	7 32#	3491	0.883	10300	1º-2º
Well 3	2200	2400	1875	3551	781	78%	7 32#	1498	0.489	9558	1º-50º
Well 4	800	3200	2240	1556	700	55%	7 32#	1495	0.705	9500	4.1º - 41.98º
Well 5	350	900	350	778	389	50%	7 32#	998	0.434	9750	4.5º - 45.3º
Well 6	2500	3100	1050	1129	339	70%	7 32#	1100	-	9000	1.2º - 35.3º
Well 7	1800	3500	1181	750	337	55%	7 32#	1494	0.773	9600	6.44º - 10.06º
Well 8	2100	3000	2244	1662	748	55%	7 32#	1494	0.773	9600	0.68º - 15.90º
Well 9	3000	4500	2140	2378	476	80%	7 32#	500	0.691	9480	0.90º - 11.90º
Well 10	3000	4500	2000	1111	444	60%	7 32#	-	-	9460	0.85º - 15.90º
Well 11	3100	4000	2000	1250	500	60%	7 32#	-	-	9360	0.91º - 8.30º
Well 12	3100	4000	2000	1250	500	60%	7 32#	-	-	9500	0.75º - 10.3º

Table 3. Sand Screen (1st Stage) Fluid Velocity

Well	Max Fluid Production Design ,BFPD (EXPECTED)	Open Area (in^2)	Fluid Velocity through Screen, in/sec	Velocity difference to reach max velocity, in/sec
Well 1	1500	1451.2	0.116068	0.08356
Well 2	4500	2176.8	0.232135	- 0.03251
Well 3	2400	1814	0.148567	0.05106
Well 4	3200	2176.8	0.165074	0.03455
Well 5	900	725.6	0.139281	0.06035
Well 6	3100	2120.8	0.164138	0.03549
Well 7	3500	2120.8	0.185317	0.01431
Well 8	3000	2120.8	0.158843	0.04078
Well 9	4500	1696.64	0.297831	- 0.09820
Well 10	4500	1696.64	0.297831	- 0.09820
Well 11	4000	1696.64	0.264739	- 0.06511
Well 12	4000	1696.64	0.264739	- 0.06511

Table 4. Sand Control design by Well

Well	Max Fluid Production Design ,BFPD (EXPECTED)	GAS RATE, MCFPD	# Tubing Screen	Helix Size	Open Area (in^2)	Chemical Screen (Y/N)	Treatment
Well 1	1500	750	4	2.7	1451.2	Y	Scale
Well 2	4500	1350	6	2.9	2176.8	N	No
Well 3	2400	1875	5	2.7	1814	Y	Scale
Well 4	3200	2240	6	2.7	2176.8	N	No
Well 5	900	350	2	2.6	725.6	Y	Scale
Well 6	3100	1050	4	3.7	2120.8	N	No
Well 7	3500	1181	5	3.7	2120.8	N	No
Well 8	3000	2244	5	3.7	2120.8	N	No
Well 9	4500	2140	4	3.9	1696.64	N	No
Well 10	4500	2000	4	3.9	1696.64	N	No
Well 11	4000	2000	4	3.9	1696.64	N	No
Well 12	4000	2000	4	3.9	1696.64	No	No

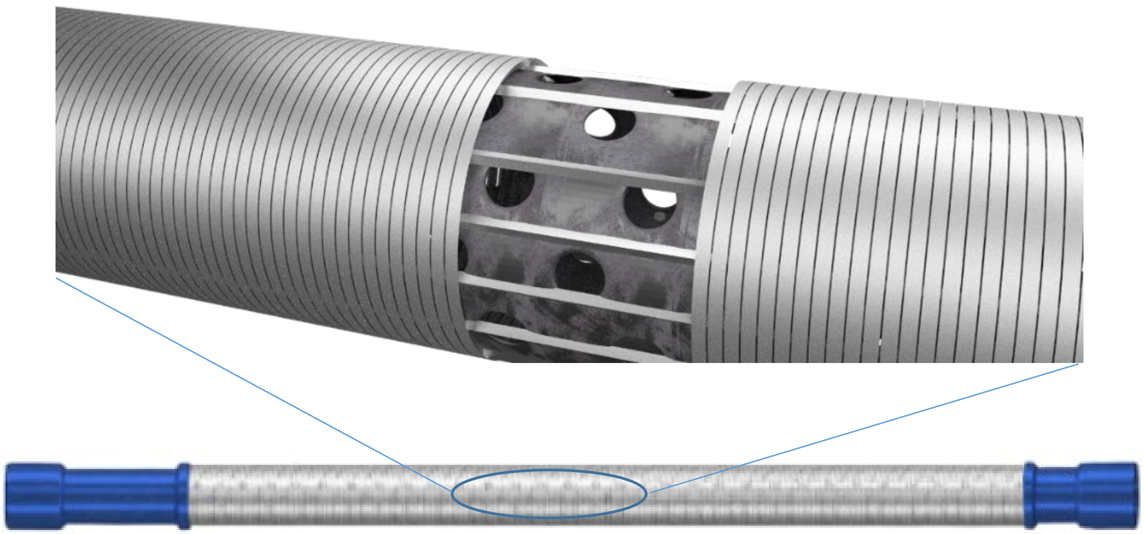
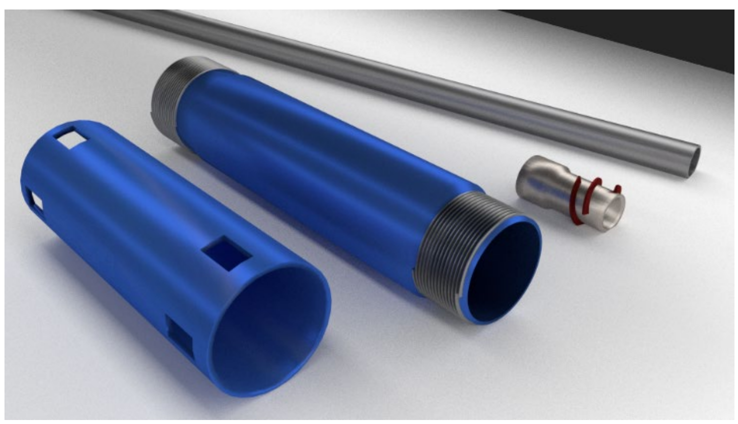


Figure 1. Sand Screen (1st separation stage)



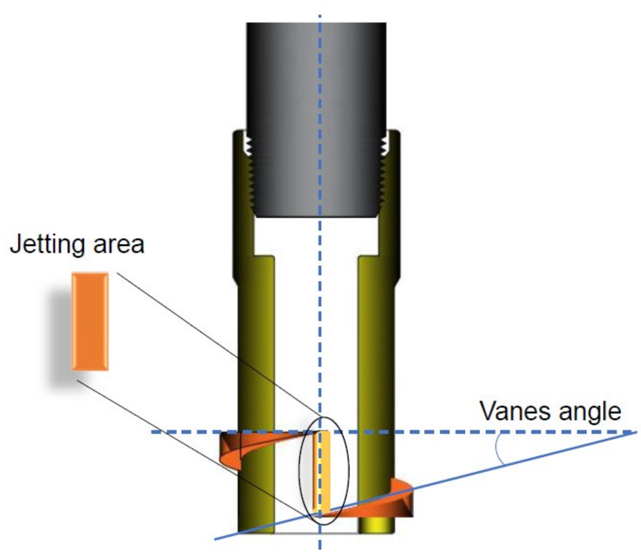


Figure 2. Vortex Generator (2nd filtration stage)

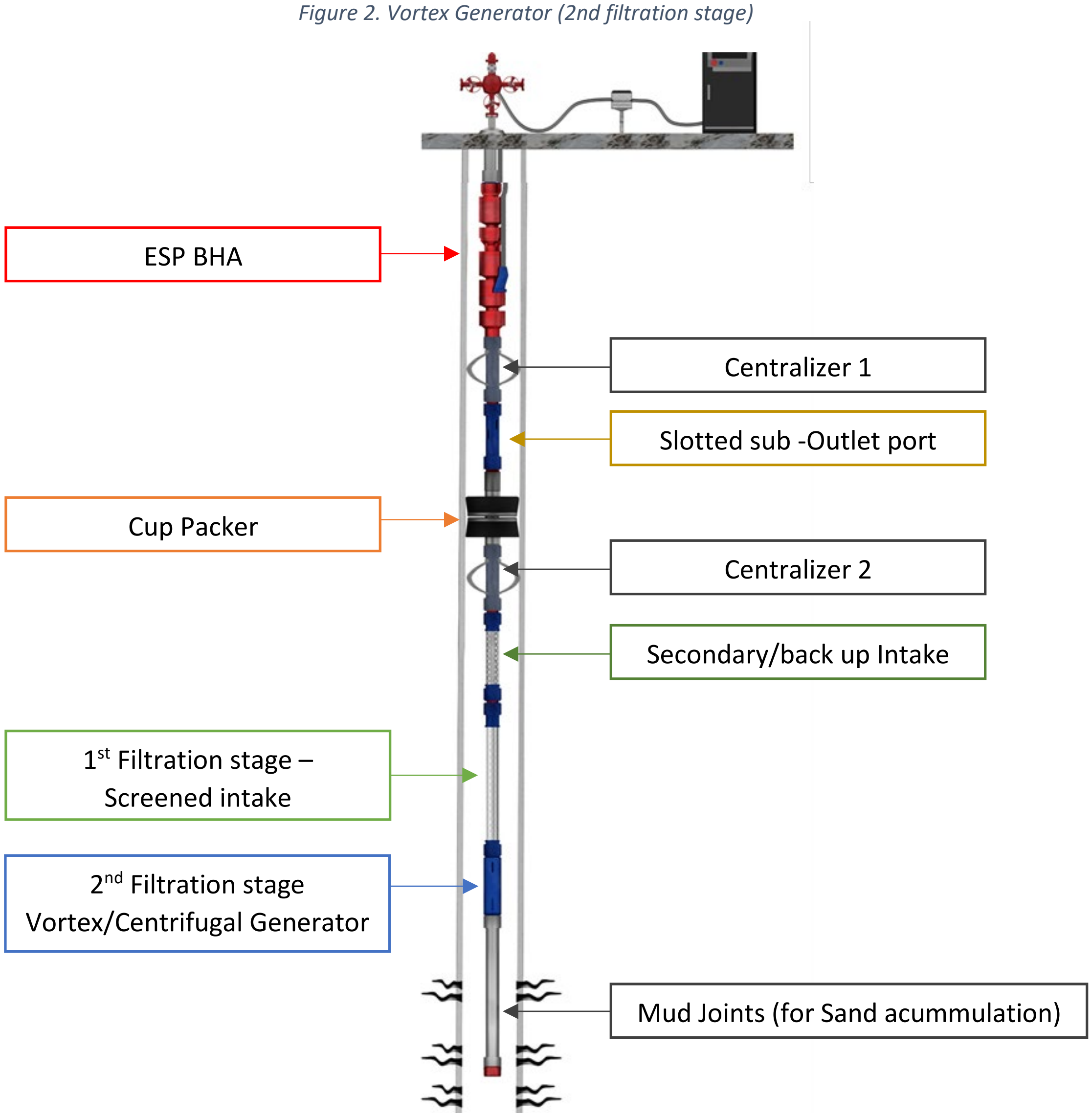


Figure 3. Dual sand control system BHA

Figure 4. Triple cup packer and Double Cup packer – Sealing Section.

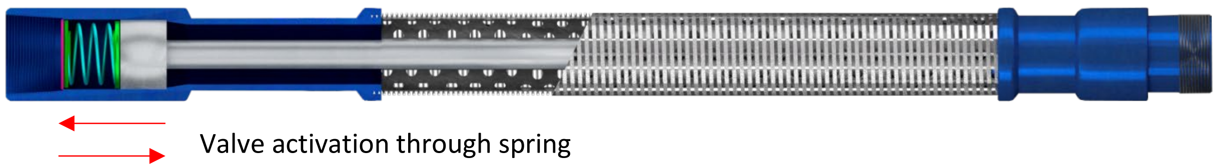


Figure 5. Secondary back up intake

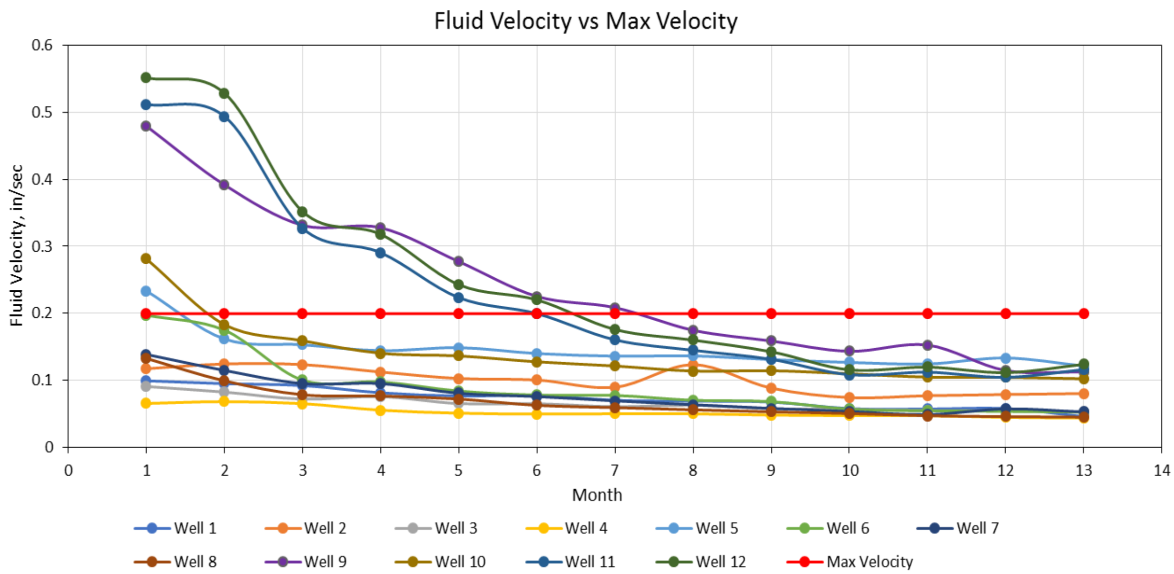


Figure 6. Fluid Velocity by Well vs Max fluid Velocity

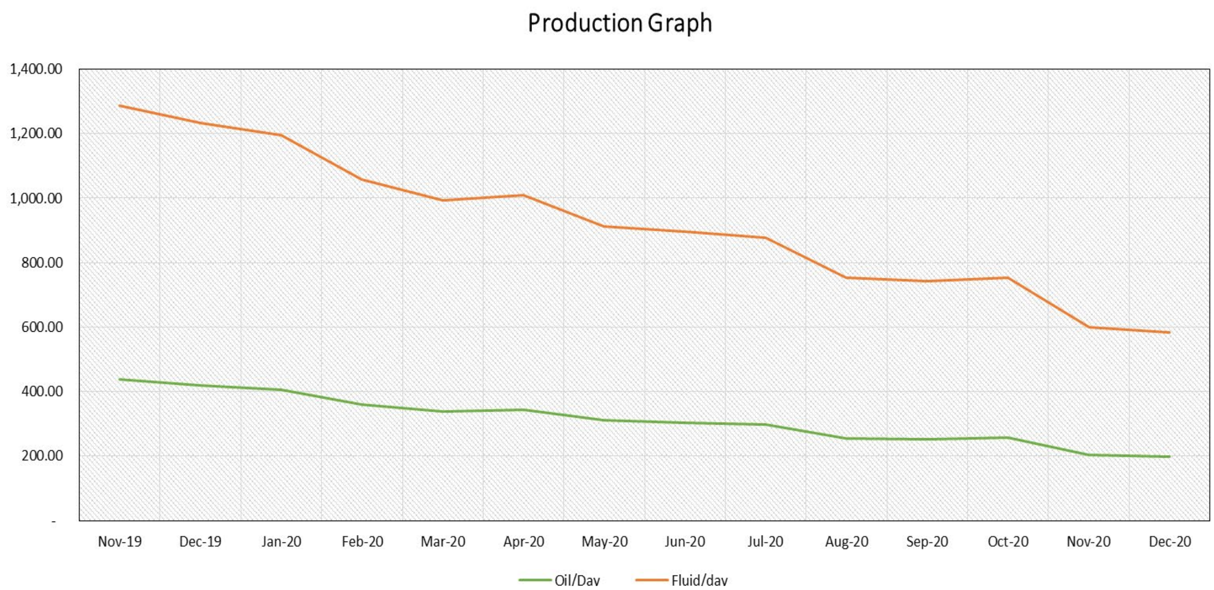


Figure 7. Well 1 Production profile

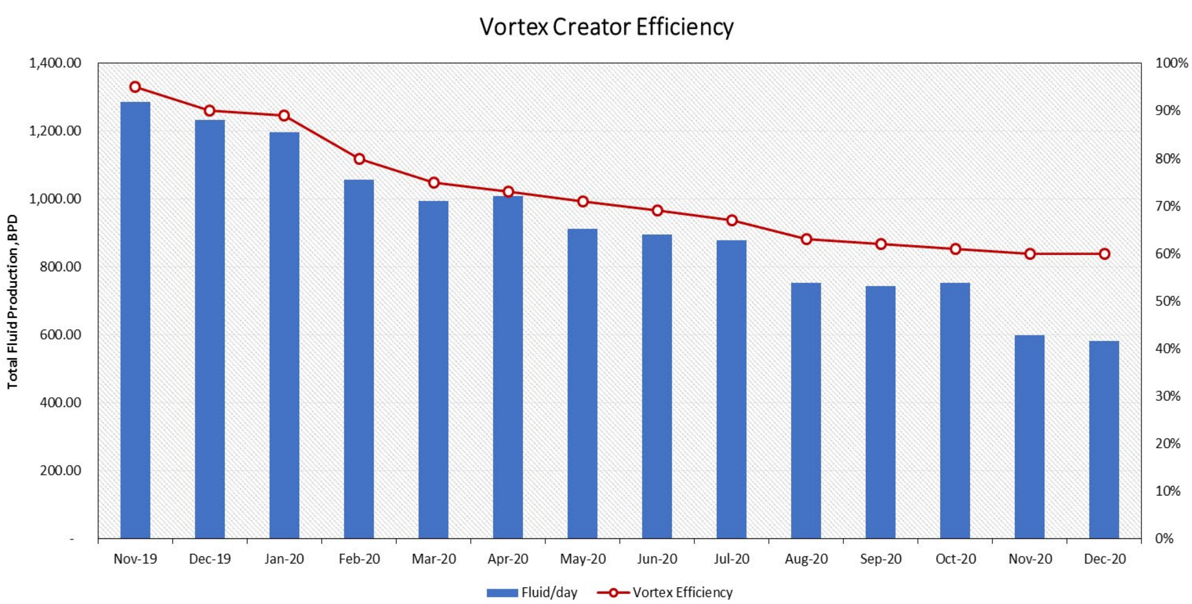


Figure 8.Well 1 Total fluid production vs Vortex generator separation efficiency

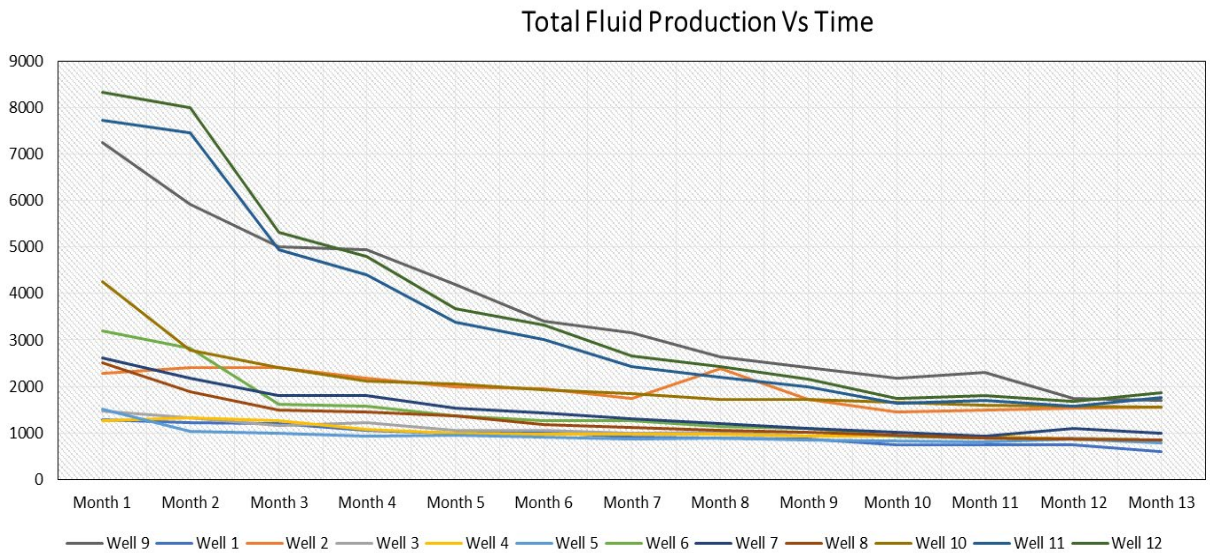


Figure 9.All wells Production profile

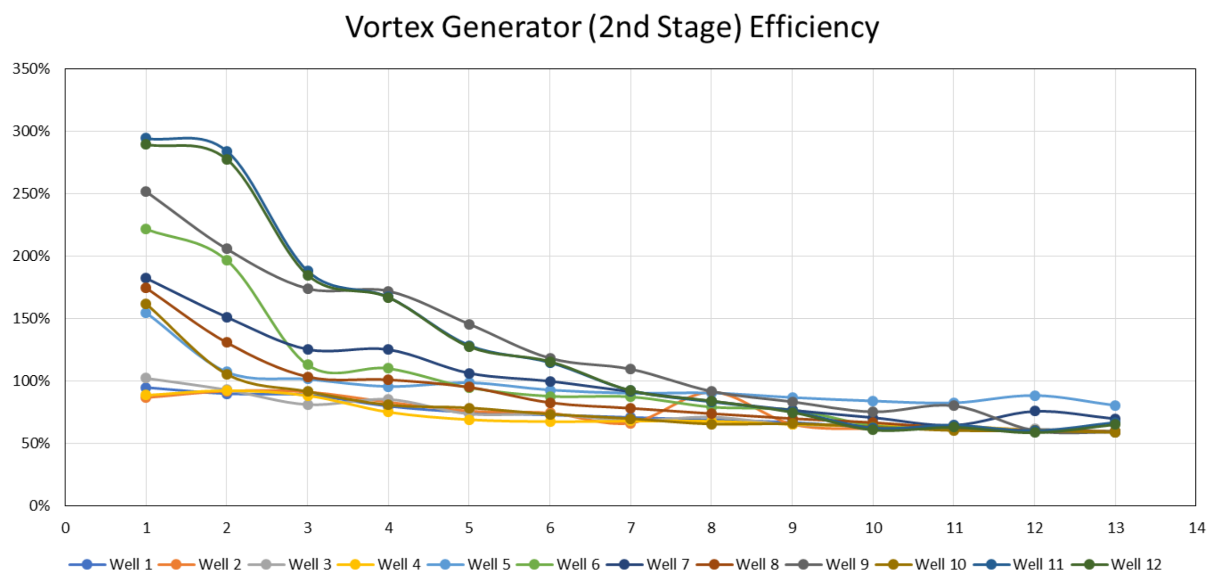


Figure 10. Vortex generator (2nd stage) separation efficiency