SOLUTION TO GAS SLUGS IN HORIZONTAL WELLS: SURGE VALVE

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ABSTRACT

Horizontal wells tend to have surges of fluid and gas when producing. Especially in the case of gas, we tend to see gas production flowing in slugs, resulting in intermittent production of liquid and gas. This unpredictability of gas slugs and surges leads to free gas entering the pump more frequently and being harder to control than in a vertical well. This can lead to decreased production, efficiency, and pump fillage. To deal with the issues that surging in horizontal wells can lead too, Odessa Separator has developed the surge valve. The surge valve was designed to help capture the surge above a packer by not allowing the surge fluid to fall back into the horizontal section. Doing this allows for each stroke of the pump to pull more gas free liquid, therefore increasing the pump fillage and the production of the well. This paper presents a case study of a well with high gas production where the surge valve was run in conjunction with a packer type gas separator to help deal with the gas. After the installation of the Packer Type Gas Separator with the Surge Valve, the production and pump fillage both increased by nearly double while also decreasing the GLR.

INTRODUCTION

In the initial stages of crude oil production, pressure above or near the bubble point limits the effects of gas on production systems. In the initial stages, operators have little record of gas failures however, as the pressure falls below the bubble point, the gas comes out of solution and begins to occupy space both in the annular section and within the pumping systems. In wells completed in unconventional reservoirs in the Permian basin, we can identify a rapid decline of the production as formation fluids are produced, this rapid decline is directly related to both the decrease in flow pressure from the reservoir and the expansion of the gas from the formation.

In the horizontal section of unconventional wells, different flow regimes can be identified that will affect the performance of artificial lift systems. As mentioned at the beginning, in the initial stage when the pressure is above or close to the bubble point, we will have a single-phase liquid flow that allows efficient production in the well (Figure 1), as the pressure is decreased and the gas in solution is released and bubbles formed in the liquid phase, giving rise to bubble flow. These bubbles, due to the difference in density, will be concentrated at the top of the horizontal section of the well. Eventually, the gas bubbles will expand as pressure decreases and will coalesce to form gas plugs inside the liquid phase, this type of flow regimen is known as plug flow and as in the bubble flow, the plugs will flow at the top of the casing. Depending on the pressure and geometry of the well, three different types of flows can be created; in wells with low flow velocity in the horizontal zone, stratified flow is formed, where the gas phase is completely separated from the liquid phase and flows in defined interfaces, on the other hand, when the velocities increase, a wave flow can occur where the liquid phase presents turbulences distorting the distribution of the phases in the casing; when the speed increases it presents the type of flow that brings the greatest problems to the pumping systems, the slug flow, where the difference in flow speeds between the liquid and gaseous phase generates the loss of liquid production due to the fact that the gas moves faster and can reach the pump in less time. All these flow regimes can appear in the wells or not, that is going to depend on the reservoir conditions, fluid properties, and production parameters. There are other types of flow regimes such as annular flow where the amount of gas forms a continuous phase in the pipe, moving the liquid to the edges of the pipe and generating a load of liquid drops in the gas phase, however, this paper will focus on problems related to the production of fluids in wells with slug flow installed with beam pump.

GAS SLUGS AND THE EFFECTS IN BEAM PUMP

Typically, subsurface pumps are installed above or just at the KOP of the well, maintaining the production assembly in the vertical section of the well, so the type of flow coming from the horizontal section of the well will directly affect the operation of the pump. Slug, wave, and stratified flows tend to promote gas surging in the curve of the well, producing a more abundant flow of gas to the pump (Figure 2) and causing the liquid to fall back to the horizontal section until the gas slugs lift the liquid or the fluid column pressurizes the horizontal zone restoring liquid flow for a period inversely proportional to the pumping speed. The downhole pump has the function of letting the fluid in and then send it to the surface through the rod string however, the mechanism of the sucker rod pump is designed to manage incompressible fluid so when gas is present inside the pump, issues such as low efficiency, gas lock or gas pounding will affect drastically on the run life of the equipment and the runtime of the well causing loses and higher investments due to interventions and pump and/or rod string changes.

Normal rod pumps manage an efficiency of 70 - 80%, but in presence of gas even though there are no physical damages, the efficiency can drop below 20%, a low pump efficiency requires more SPM which means more power consumption reducing equipment life. The main problem resides at the start of the upstroke when there is gas between the standing valve and the traveling valve and when these two are at the bottom of the downstroke, the gas inside is compressed and when the plunger begins the upstroke the standing valve can only open when the pressure above has decreased to the submergence pressure, this delay on the opening cause less filling and therefore less fluid pumping to the surface (Figure 3).

To deal with downhole gas, gas separators and accessories are installed with the pump, but the handling or separation capacity is usually low due to the size of the casing and the diameters of the pipe and pump. Some of these systems, although efficient, can be affected by the gas surging in the well and the little retention of liquid in the section near the intake of the pump. To help the downhole devices, operational measures such as POCs are used to mitigate the effects of gas slugs in the pump but limit the potential of the well and produce less liquid than expected.

SURGE VALVE: SOLUTION FOR GAS SLUGS

The gas surging from the horizontal zone is then identified as a major problem to reach the designed capacity of the subsurface pumps, especially in beam pumps. Through the analysis of the flow behavior of several wells in Yoakum County in the Permian basin, it was possible to identify cyclical production behaviors, where the decrease of pressure in the formation produced a constant flow of gas that drastically reduced the liquid production. This low production cycle was maintained until the column pressure was restored and the gas slugs were reduced to bubble flow. This surge behavior led to the development of a technology with the ability to maintain a column of liquid in the vertical section of the well, dispersing or resolubilizing the gas slugs. The Surge Valve uses a check-type mechanism that retains the column of liquid in the annulus and prevents the liquid from falling back into the horizontal section of the well, maintaining an always constant level for filling the pump. The internal flow system in the tool has 4 channels, 3 channels designed to allow the passage of fluid from bottom to top, and a fourth channel with a dual purpose: chemical injection below the surge valve and packer seal test. This last function solves the uncertainty about the correct activation and the proper seal of the mechanical packers, the test system must be designed based on the installation depth and the fluid column in the well. Figure 4 shows a schematic of the valve that is installed in two ways:

- In standalone with a mechanical packer at the KOP
- In conjunction with a packer type gas separator

The second installation method proved to be highly efficient in performance tests because as the fluid passes through the valve, the gas-liquid mixture forms a bubble flow that at the pump intake can form small slugs due to gas expansion (Figure 5). To ensure that this free gas does not reach the pump, a packer type gas separator was installed above the packer + surge valve assembly which ensured longer periods of liquid production and gave the possibility of operating the pump at a higher speed. The type of installation is chosen based on the well conditions and the production parameters used, however, due to the results obtained, the use of the combined surge valve + packer type gas separator system was recommended in all installations. The design criteria will be reviewed below.

DESIGN PARAMETERS

To design the type of system to be used in each well, it is important to diagnose the type of flow regime and the amount of free gas present at the intake of the pump. The diagnosis can also be carried out by monitoring the production variables identifying cycles of low pump fillage and interference by gas followed by stages of high pump fillage, these cycles usually indicate a high presence of free gas in the pump (figure 6).

Fluid properties and operating parameters are required for the determination of the problems of the wells. The data required for diagnosis are summarized in Table 1. PVT data can be calculated by correlations or determined in laboratory tests to reduce uncertainty. The objective is to identify the type of flow regime to compare with the percentage of free gas determined at the intake of the pump. Based on the results of the diagnosis, wells with slug flow regime can use the Surge Valve to mitigate this problem and obtain a more homogeneous flow at the pump intake, however, if the percentage of free gas calculated is greater than 15%, It is recommended to use the Surge Valve in combination with the packer type gas separator. Other experiences have shown that in wells installed with a Packer Type Gas separator, where the GLR was greater than 1,000 SCF/STB, the separator performance can be improved by installing the surge valve below the packer; a case study will elaborate more on this finding.

Regardless of the type of assembly chosen, the Surge Valve testing system must be properly designed based on the installation depth and maximum fluid column of the well. This will allow to maintain the seal, holding the hydrostatic pressure above the packer and in turn will allow to test that the packer was seated correctly. The designed test range will also dictate the pressure required to treat the well section below the packing, if required.

FIELD LOCATION AND ANALYSIS

The development of the surge valve was based on the analysis of the behavior of several wells in a field in West Texas, in Yoakum County (Figure 7). All the wells are horizontal and are completed in the San Andres formation, starting the production period with electrical submersible pumps. After the depletion period is fulfilled, the wells are converted to beam pump and the pumping system is designed to reach a potential of up to 600 BFPD, however, the constant problems generated by gas production limit the production capacity and generate an erratic behavior of the fluids in the well. Figure 8 shows the behavior of production in two wells converted from ESP to rod pump, the graphs show high initial potentials followed by low productions because of low pump fillage and severe gas interference as shown in figure 6. Although the gas volumes are not considerably high, due to the amount of free gas in the well, the interference can be severe and therefore it is important to determine this parameter with the most drastic production variables that can be simulated.

After evaluating the problem based on production data and pump parameters, the calculations of the flow regime and amount of free gas were carried out with this process being explained in the next section. From the problem, an initial solution was then considered using a packer type gas separator. Although this type of separator is quite efficient, and generally show positive results, the limitation of the casing size is a factor to consider because almost all wells in the Permian Basin use 5-1/2” 20# casing. Which in terms of gas separation, represents a decrease in cross-sectional area and therefore, a lower separation efficiency. This is quite a drastic limitation and led to the development of a system that focused on the origin of the problem rather than on mitigating its effects. By identifying the type of flow regime and the amount of free gas, the operator determined that a viable solution was to prevent the gas slugs from passing directly to the pump and instead being dispersed and solubilized in the liquid phase. After analyzing the production data of some wells that have a surge valve installed, we confirmed there was a positive impact on the below wells.

CASE STUDY A

After being converted from ESP to rod pump, the well had an average fluid production of 164 BFPD with a maximum production of 200 BFPD as shown in table 2. During the period analyzed, the well had a GLR of 1005 SCF/STB, with an average pump fillage of 43% and pumping speed of 9 with 144” of stroke length. Based on these conditions, the operator determined the well was slugging and that was causing a low pump fillage and then low pump efficiency. One of the methods used to determine the flow regime in vertical pipe is described by Orkiszewski, J. combining the methods of Griffith, Griffith and Wallis, and Duns and Ros. By determining the parameters proposed it can be identified the type of flow regime between bubble, slug, transition, and mist. After this evaluation, the next step was estimating the free gas at the pump intake. This estimation is made based on a volumetric balance defining the volumetric factor of oil, gas and water and the solubility of gas, at the pump intake pressure and bottom hole temperature. Typically, free gas percentage of 15% or higher are considered harmful for the pump efficiency and integrity of the downhole equipment so the use of a downhole gas separator is justified. With this analysis, it was found that the well was slugging with a free gas percentage higher than 15% at the pump intake.

Because of the gas volume, the most feasible option was using a Packer Type Gas Separator (PTGS) to increase the fluid production, so the OSI PTGS and surge valve were sized based on the well information using a rotational packer and a perforated joint as an intake below it. BHA installed is showed in figure 9.

The gas separator and surge valve were installed on September 18, 2020, obtaining immediate results. The average fluid production passed from 164.2 BFPD to 302 BFPD (84% more fluid production) which in terms of oil production was an increasing of 18 BOPD after the installation (Table 2). By comparing the maximum productions achieved in both periods, it’s clear that success of this application going from 200 BFPD (9.8 spm, 144” SL) to 400 BFPD (9.9 spm, 144” SL) and achieving a maximum oil production of 85 BOPD (30 barrels more than before). The well then went down due to iron sulfide issues, with the operator choosing to use the exact same BHA, albeit with new tools. The new installation was then installed in Well A on January 3rd, 2021, using the performance, pre-OSI tools, as the baseline.

The production graphic (Figure 10) shows the performance in each period: Packer Type Gas Separator + SV 1st installation, and Packer Type Gas Separator + SV 2nd installation. Clearly after adding the New Surge Valve to the BHA, there was an increase in the production of fluids and naturally in the production of oil. According to table 2, the average production was 429 BFPD, reaching a maximum production of 610 BFPD, which is a 42% increase in the average production of the well. Regarding oil production, it went from 57 BOPD to 71 BOPD on average, that is an increase of 13 barrels with respect to the installation with the PTGS and of 31 barrels per day with respect to the period before the installation of OSI equipment. Figure 11 shows the behavior of the minimum, average, and maximum oil production in each of the evaluated stages. In the maximum production scenario, the greatest difference was evidenced, going from 55 and 85 BOPD before OSI and with the installation of the PTGS and surge valve, respectively, to 120 BOPD (65 and 35 additional barrels of oil) with the installation of the Surge Valve.

The application carried out in well A allowed to conclude that the use of the Surge Valve in wells with slug-type flow and a high percentage of free gas improves pumping efficiency, allowing better handling of free gas by eliminating the continuous gas phase, converting it into dispersed bubbles in the liquid. In general, an improvement in the performance of any well can be expected by using the Surge Valve, while maintaining the same production parameters.

CASE STUDY B

Before the installation, the well was installed with an OSI Packer Type Gas Separator (PTGS) and it was producing 387 BFPD with a maximum production of 573 BFPD as shown in table 3. Although the gas production was not significant, the production was lower than the pump capacity and the operator was looking for a solution to increase production. By using the analysis described in the Case Study A and identified the slugging nature of the fluid in the well, the operator decided to use the Packer Type Gas Separator with the Surge Valve (PTGS + SV) to increase fluid production.

The gas separator was installed on January 2, 2021, with the design showed in figure 9. The average fluid production passed from 386.7 BFPD to 443 BFPD (56 barrel additional) which in terms of oil production was an increasing of 3 BOPD after the installation (Table 3). The evaluation of the maximum production shows more significant data, for instance, before the installation the maximum production achieved was 573 BFPD (10.9 spm, 144” SL) and after the installation 616 BFPD (10.3 spm, 144” SL) were reported with a maximum oil production of 174 BOPD (65 barrels more than before the installation).

The production graphic (Figure 12) shows the fluid production before and after the installation of the PTGS + SV and the oil production is showed in figure 13. After the performance recorded for these two wells, the tools were standardized in the field in wells presenting surging and high percentage of free gas a t the pump intake.

CONCLUSIONS

- The Surge Valve tested its use to disperse gas slugs in the vertical section and increase fluid production.
- In cases where gas locks led to low run time, the use of the Surge Valve promotes more stable and longer production periods, increasing the accumulated oil produced.
- The dispersion mechanism of the Surge Valve improves the performance of the Packer Type Gas Separators, thus increasing the volumetric efficiency of the pump.
- The surge Valve can be used to test the effective seating of mechanical Packer. The test system must be designed for the specifications of each well, considering the fluid level of the well.
- The Surge Valve allows the injection of fluids below the packer, which facilitates chemical treatments or stimulations to the formation without needing to pull the tubing.

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Table 1. Parameters for Diagnostic

EVALUATION PARAMETERS
API
Specific Gravity of Water, SGw
Specific Gravity of Water, SGg
Liquid Viscosity
Gas Viscosity
BHT
Static Pressure
Qo, Qw, Qg
Pump Intake Pressure, PIP
Gas Solubility, Rs
Volumetric Factor of Oil, Bo
Compressibility Factor, Z

Table 2. Production Parameters – Well A

Installation		Oil Production BPD	Gas Production MCFD	Water Production BPD	BFPD	Wcut %	GLR	Pump Fillage %	Strokes Per Min	Stroke Length
Before OSI	Min	22.8	123.9	81.9	114.4	69.6%	807.5	21.0	8.0	144
	Avg	39.6	162.8	124.7	164.2	75.7%	1005	43.6	9.0	144
	Max	54.8	186.4	157.1	200.7	82.8%	1303	80.2	9.8	144
PTGS + SV 1	Min	15.5	69.8	34.4	59.6	57.7%	336	15.9	9.5	144
	Avg	57.5	198.5	244.3	301.8	80.1%	692	62.3	9.7	144
	Max	84.7	272.2	344.2	400.3	89.6%	1435	99.0	9.9	144
PTGS + SV 2	Min	32.9	163.1	182.9	216.5	76.7%	427	13.6	9.4	144
	Avg	70.7	238.3	358.0	428.7	83.5%	572	62.5	9.5	144
	Max	119.5	475.4	515.1	609.9	89.6%	1295	97.7	10.2	144

Table 3. Production Parameters – Well B

Installation		Oil Production BPD	Gas Productio n MCFD	Water Production BPD	BFPD	Wcut %	GLR	Pump Fillage %	Strokes Per Min	Stroke Length
PTGS	Min	3.5	5.5	41.0	47.1	72.0%	116.7	13.8	9.4	144.4
	Avg	72.9	180.2	313.8	386.7	80.0%	465.9	40.9	10.7	143.7
	Max	109.2	299.0	478.0	573.2	97.0%	521.6	65.9	10.9	144.4
PTGS + SV	Min	3.9	0.6	32.0	47.5	56.0%	13.2	7.7	3.95	144.4
	Avg	75.7	202.2	367.2	442.9	82.0%	456.5	41.7	10.3	144.4
	Max	174.1	380.6	561.0	615.9	97.0%	618.0	50.8	10.8	144.4

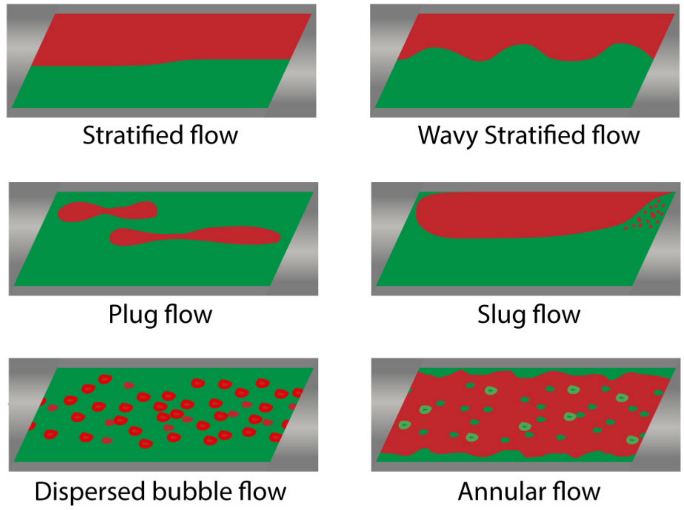

Figure 1. Flow Regimens in the horizontal section of the well

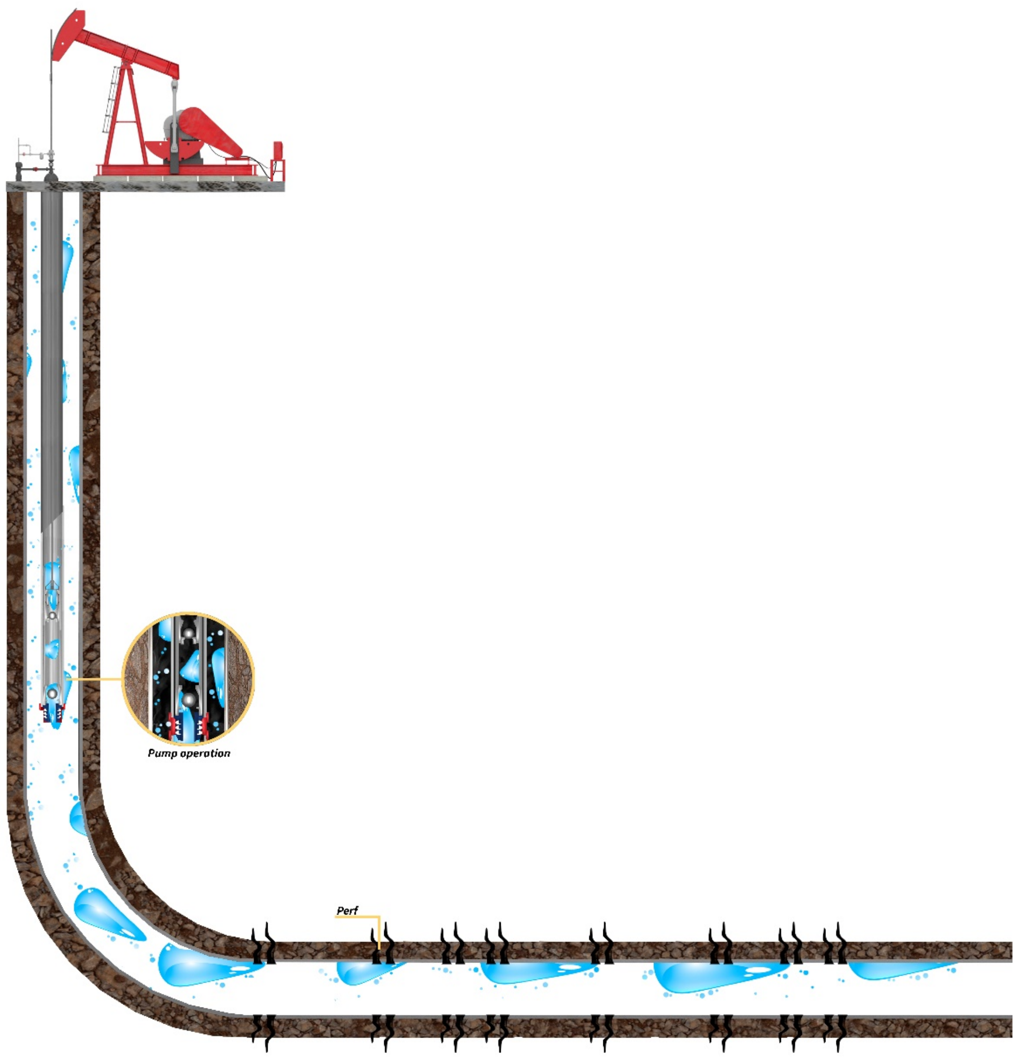

Figure 2. Gas slugs – Beam pump

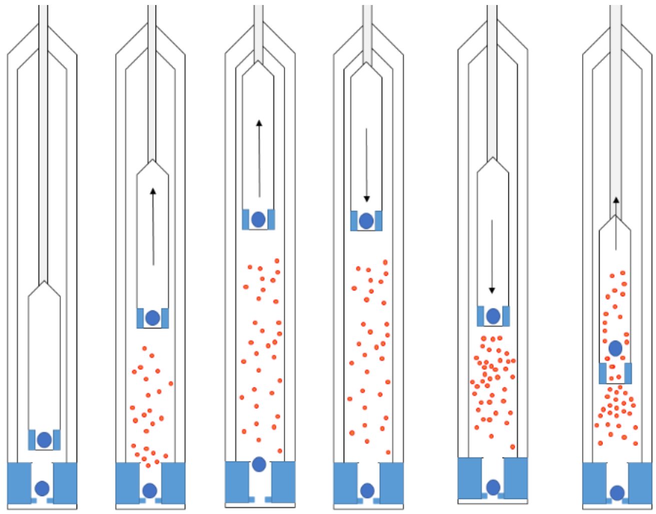

Figure 3. Gas effect inside the pump

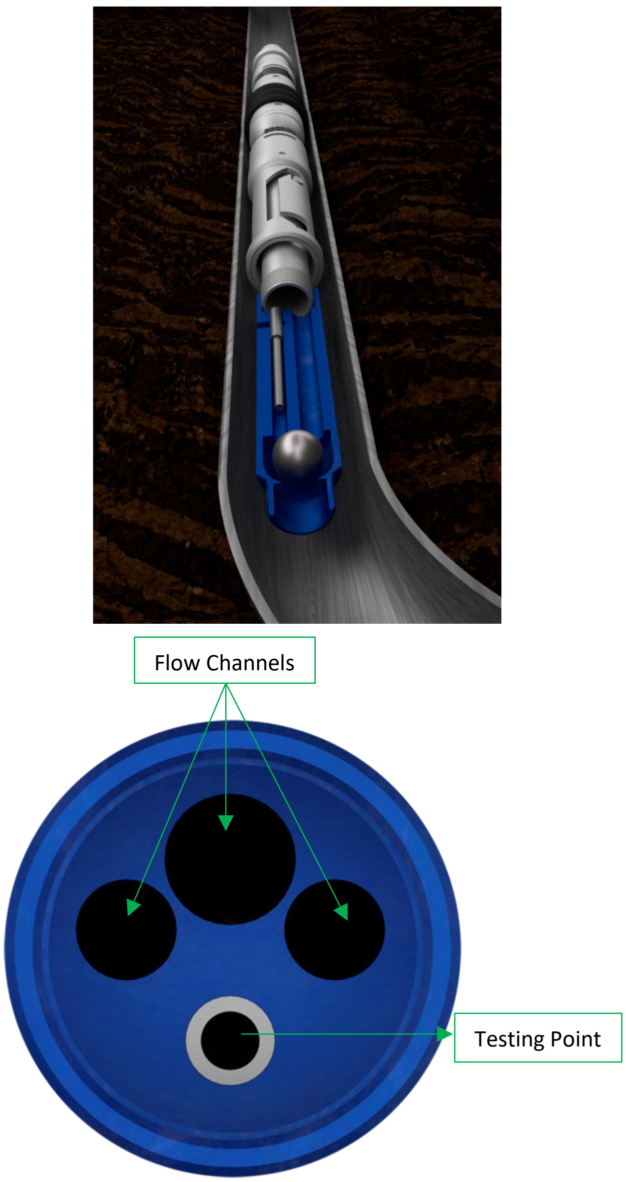

Figure 4. Surge Valve - Sketch

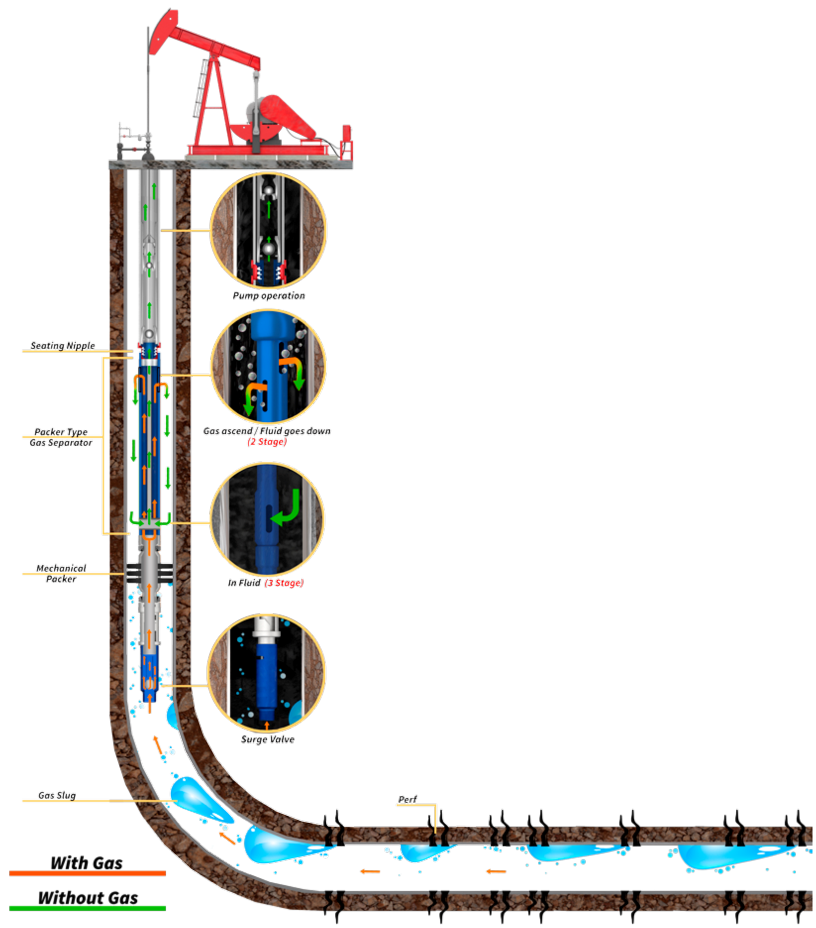

Figure 5. Surge Valve + Packer Type Gas Separator

Figure 6. Well with cyclic behavior. Gas Problems

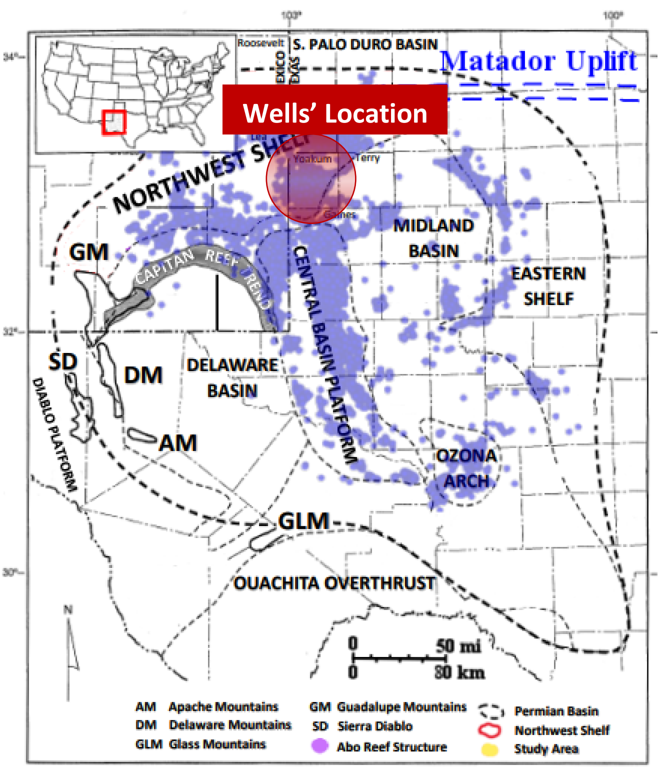

Figure 7. Wells' location – Ruppel S., 2019

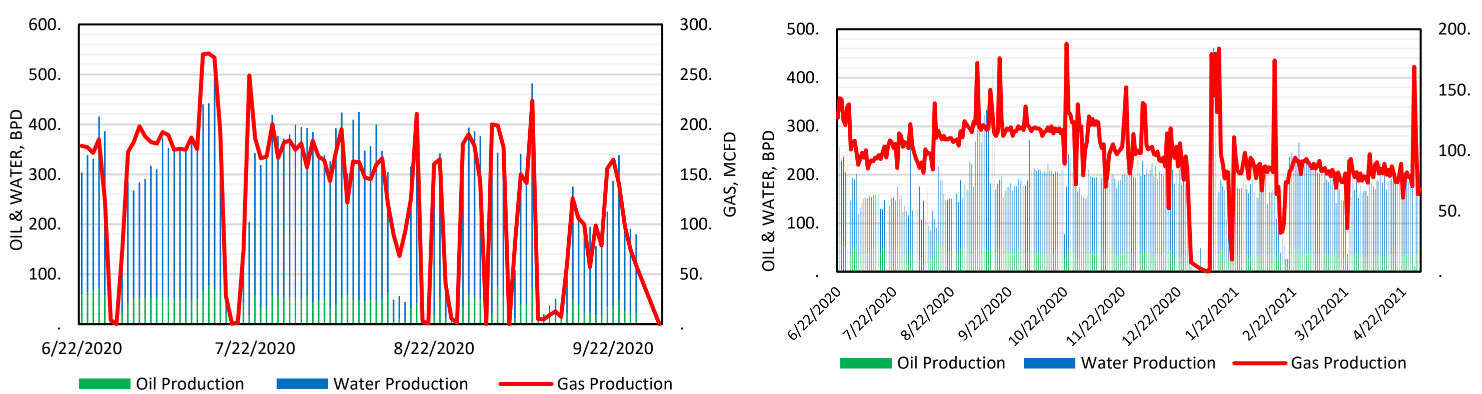

Figure 8. Typical fluid production-Field analyzed.

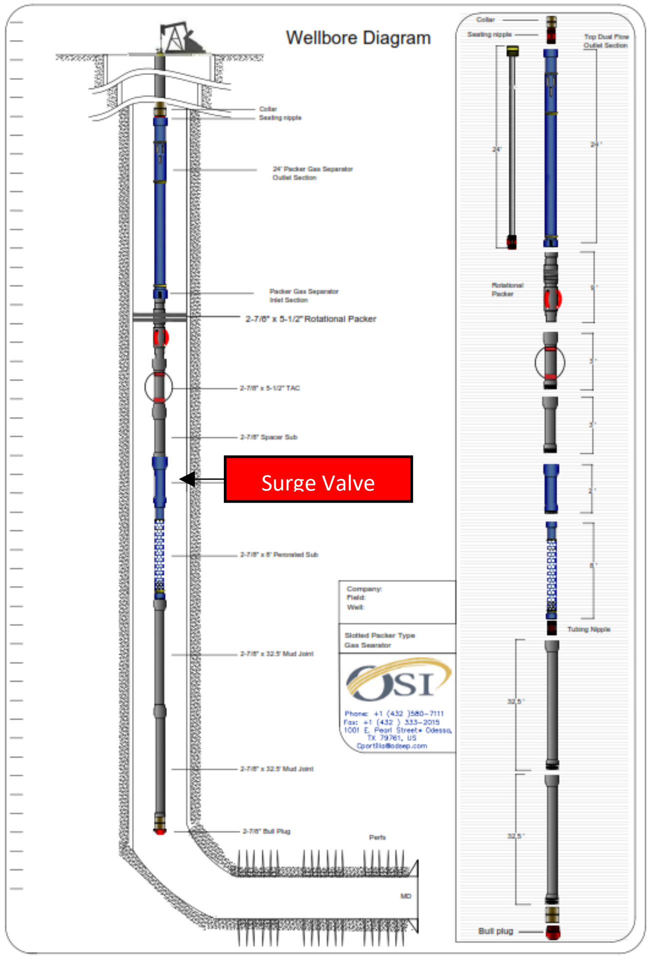

Figure 9. PTGS + SV BHA – Well A.

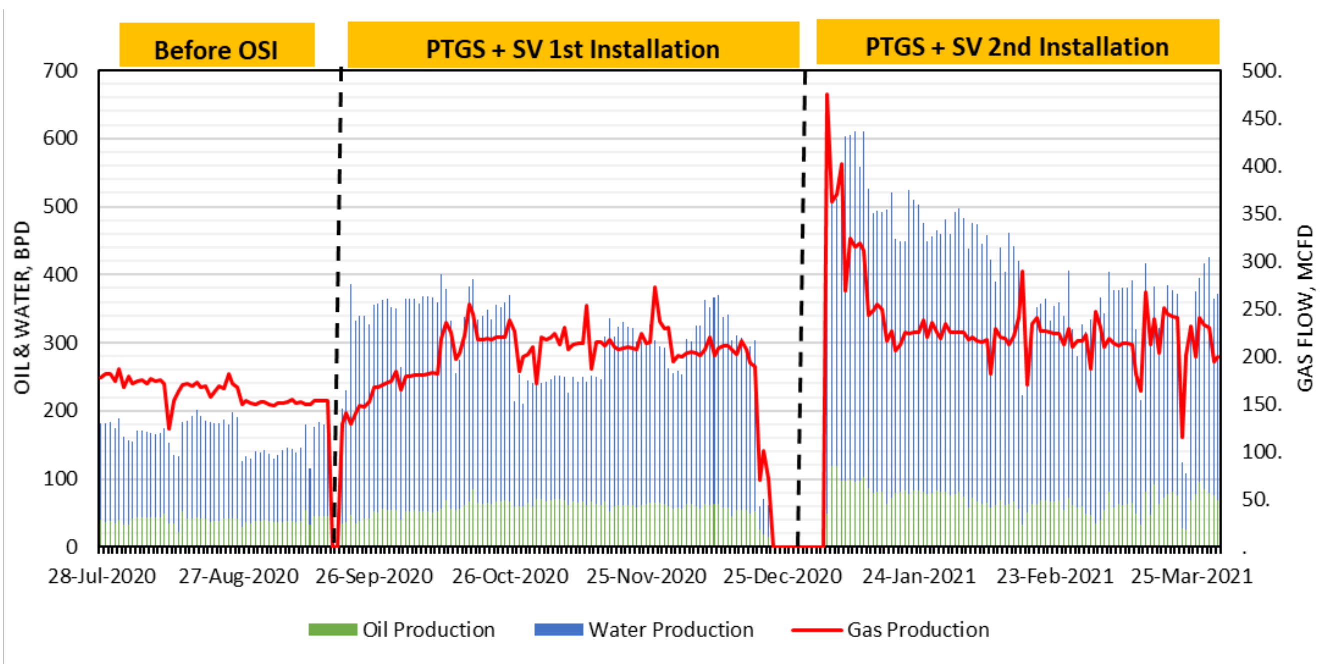

Figure 10. Fluid production – Well A

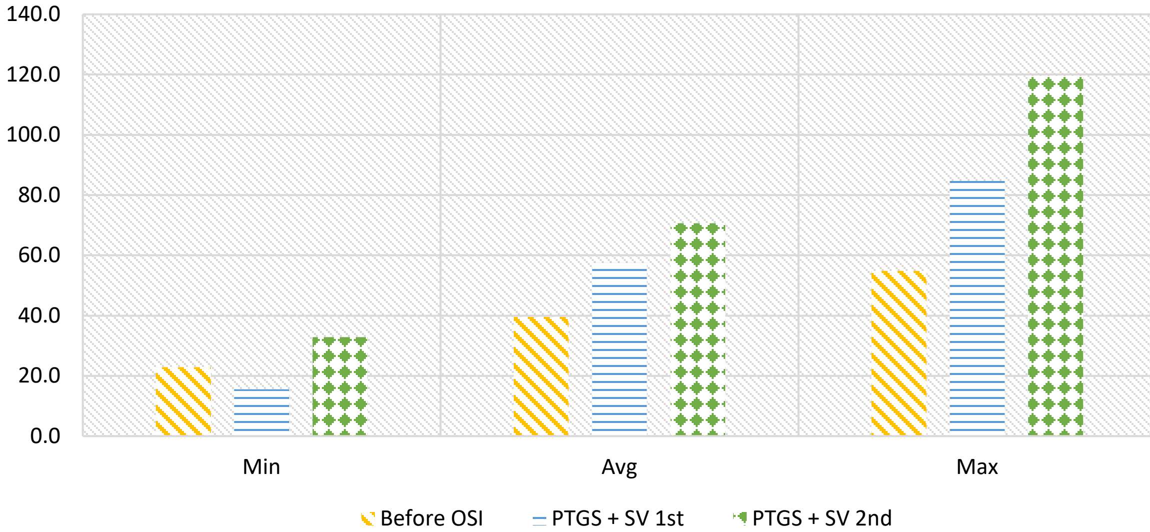

Figure 11. Oil production – Well A

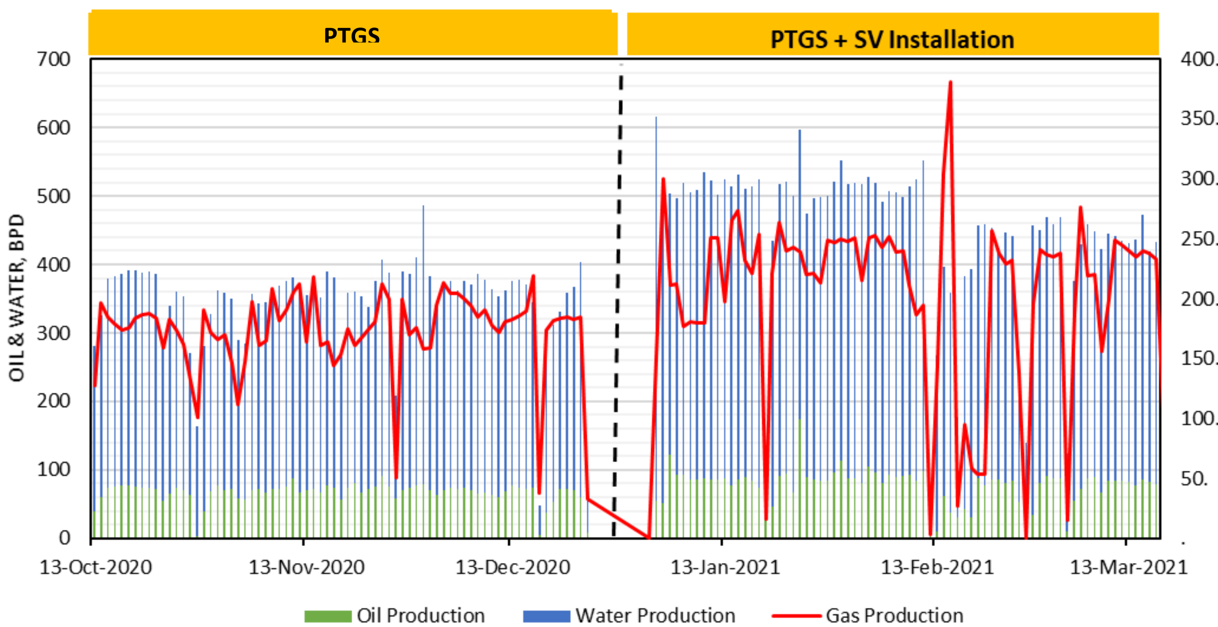

Figure 12. Fluid production – Well B

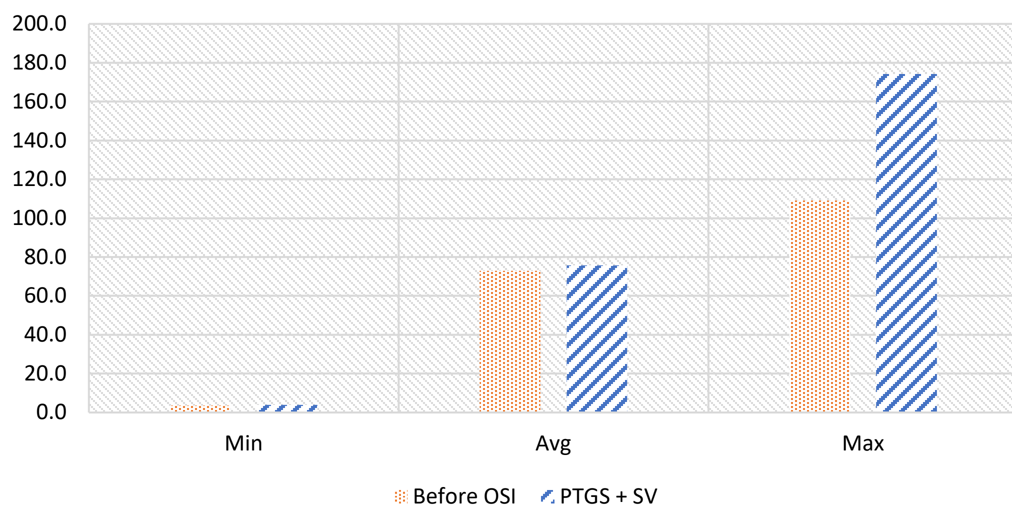

Figure 13. Oil production – Well B