HOW TO DESIGN YOUR BHA TO MAXIMIZE PRODUCTION AND STABILIZE PUMP FILLAGE IN UNCONVENTIONAL GASSY WELLS

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ABSTRACT

Gas and solid separation remain one of the main challenges for operators in the oil and gas industry. Unnecessary shutdowns lead to both lost production and difficult pumping conditions while damage over time from solid abrasions causes mechanically incurred erosion failures. With a well-designed Bottom Hole Assembly (BHA), these challenges can be mitigated for optimal production.

Operators should maximize separation area while accounting for industry-standard downward fluid velocity in order to increase production. Less gas through the pump means less gas interference cards or pump off cards, and therefore increased drawdown. [1]

Appropriately designed BHAs avoid unnecessary shutdowns and lost production which in turn enables stabilized pump fillage, decreased Gas to Liquid Ratio (GLR) and better overall reservoir drawdown.

By achieving proper gas and solid mitigation, operators ultimately raise profitability and are allowed more freedom in pumping practices with or without lowering the pump in the curve. Operator data showing the impact of this new technology is presented.

INTRODUCTION & BACKGROUND

When producing unconventional wells, gas and solid separation can be the difference between a successful, proactive high revenue installation and an inefficient, reactive pit of lost production. During the fracking process, hundreds of perforations are made across the lateral, creating many zones with different permeability, porosity and reservoir conditions.

As the operator draws down the well, lateral zones unload due to the decrease in hydrostatic pressure. As those zones unload, the wellbore is overrun with gas and solids.

Gas interference causes premature shutdowns and lost production. Correct procedure by industry standards would call to pump through the gas as opposed to stopping the pump, which could allow gas and solids to accumulate in both the annulus and the pump.

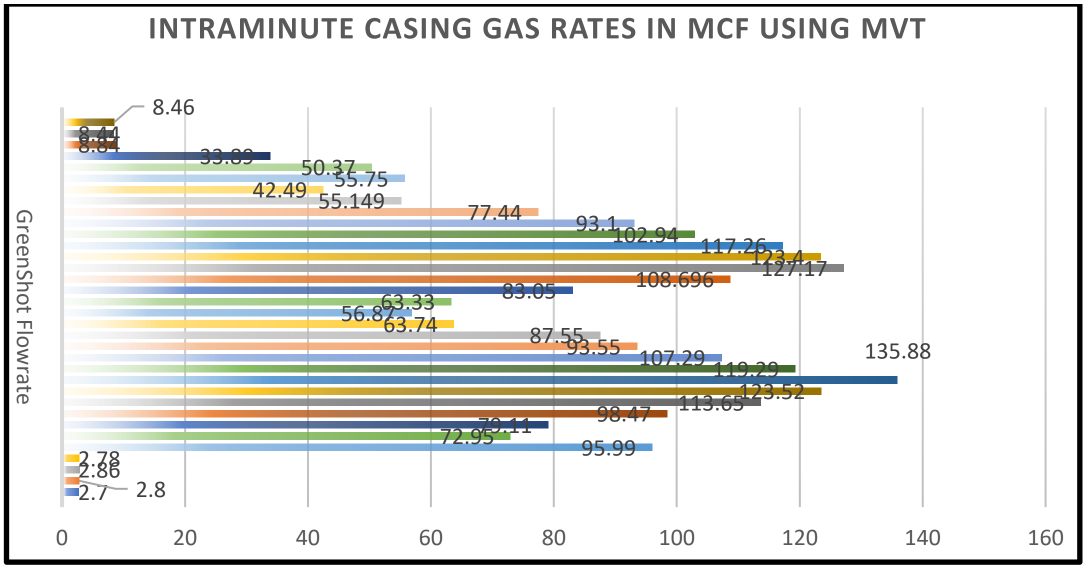

Figure 1: Casing Gas Rates in MCF using a multivariable transmitter.

Figure 1 shows the erratic gas behavior that occurs on a well, often without operator knowledge. A single daily average of gas production is typically recorded but doesn't clearly show the whole picture.

A well might average 50 MCF/day, but the quantity might fluctuate wildly throughout the day. Figure 1 shows how a casing gas rate can fluctuate from 8 MCF all the way up to 135.88 MCF and back down to 2.7 MCF in as little as 30 minutes. If the BHA was not designed in anticipation of this phenomenon, gas will overrun the separator and produce gas interference, which in turn causes a premature controller shutdown based on low fillage. This can cost the operator missed production and revenue.

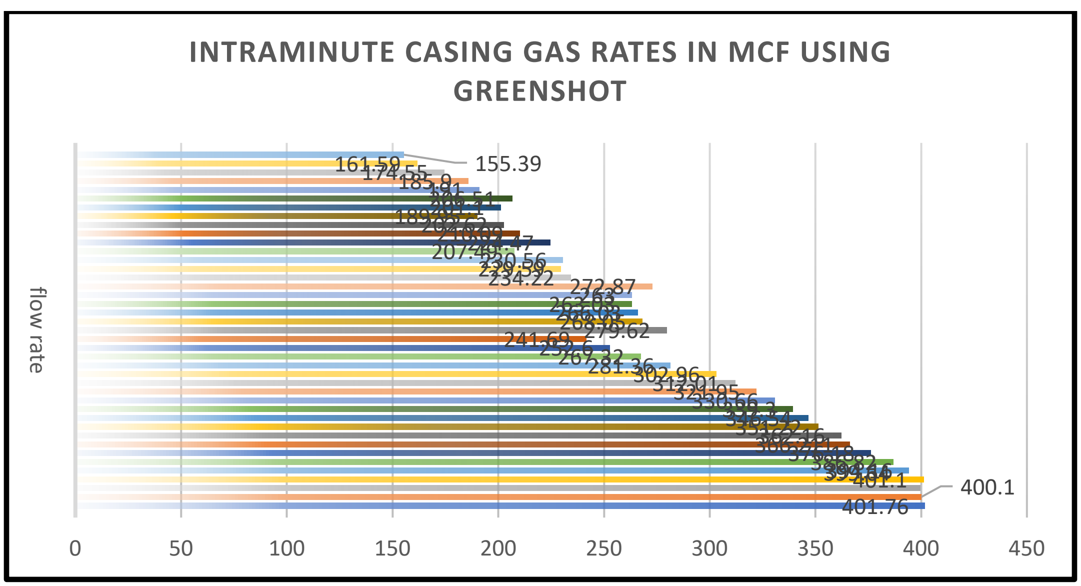

Figure 2: Casing Gas Rates in MCF using a multivariable transmitter.

Figure 2 shows another example where the extraordinary behavior of casing gas rates can be observed. In this instance, casing gas rates balloon up to 400 MCF from 155 MCF in just a little more than 30 minutes; an increase of 250 MCF. This data was collected using a permanently installed fluid level device.

Gas and solid separators are commonly used to improve efficiency on installations dealing with gas interference and solids. Two main types of gas separator exist: Poor Boy and packer style, cf. [2,4].

Solids passing through the pump can lead to erosion failures, which incurs costly repairs. [1] Two main types of solid separation exist: Mesh or vortex style, cf. [5].

In this paper, a downhole tool designed to mitigate gas and solids with the largest separation area in history is presented. Details on the procedure to design a properly fitted BHA are shared as are the concepts of total fluid rate and downhole fluid velocity.

Results are presented to show stabilization of pump fillage, increase in production and runtime as well as decreased gas to liquid ratio. Case studies showing before and after data and downhole cards are also presented.

Figure 3 shows a schematic of a deviated wellbore with multiple frac zones and how the tool is to be placed inside the wellbore.

BHA design methods and theory are shared along with a description of how the tool is composed and its operation. Field data showing the benefits and strengths of the tool are presented in the Results and Discussion section, followed by conclusions.

BHA DESIGN REQUIREMENTS

Downward fluid velocity (DVF), also known as bubble rise velocity, represents the rate gas bubbles rise in inches per second. Since bubble rise occurs at 0.6 ft/sec in fresh water but faster in an oil and gas environment, bubble rise velocity is a critical data point. [1]

Based on many field experiments as well as additional field tests, an industry standard has been set for DFV of 0.4 ft/sec. This standard rate is a guideline for proper separation. If DFV stays under the standard rate of 0.4 ft/sec, it is assumed the gas in solution stays in solution. However, if the DFV exceeds the standard rate, gas will break out of solution and eventually overpower the gas separator.

Figure 3: Wellbore showing multiple frac zones and placement of the tool.

Equation 1 shows the calculation of DFV and is a very important step in BHA designs. This equation takes into account the total barrel of fluid, the inner diameter of the casing as well as the outer diameter of the separator.

$$\frac{Q * 0.0119}{{ID_{CSG}}^2 - {OD_{SEP}}^2} = DFV = Downward\ Fluid\ Velocity \qquad (1)$$

Inner Diameter	3.625
Outer Diameter	1.050
Desired Production (BBLS / 24 HRS)	400
Downward Fluid Velocity (Target Fluid Velocity <= .400)	0.395

ID^2 =	13.141
OD^2 =	1.103
Area =	12.038
Inches/Barrels =	4.760

$$FV = \frac{.0119 \times (\text{Production})}{ID^2 - OD^2}$$

Table 1: Downward Fluid Velocity using the separator for 400 Bbl./day production rate.

In Table 1, the DFV is calculated for the tool. This gas separator has an OD of 1.050 inches. When matched with a casing ID of 3.625 inches, calculations show that for 400 BBLS/day, the DFV of the produced fluid is 0.395. The gas will stay in solution at that production rate, proving the effectiveness of this downhole separator.

CASING SIZE	COMPANY NAME	TOOL STYLE	CROSS SECTIONAL SEPARATION AREA π (R^2-r^2)	SEPARATION AREA (in^2) (D^2-d^2) For Volume Calculation	FLUID VOLUME	LENGTH OF TOOL (IN)	STORAGE CAPACITY (bbl)
4.5”	Company 1 & 2	2-3/8” Packer Style Separator	8.14	10.36	348	480	0.40253
4.5”	Company 1	2-7/8” Packer Style Separator	6.07	7.73	260	480	0.30054
4.5”	Company 2	2.5” Mother Hubbard	3.43	4.37	147	300	0.10605
4.5”	**WellWorx**	**3” HALO**	**3.11**	**3.96**	**133**	**240**	**0.07694**
4.5”	**WellWorx**	**THE MAX**	**9.73**	**12.39**	**416**	**480**	**0.48144**
5.5”	Company 1 & 2	2-3/8” Packer Style Separator	13.67	17.40	585	480	0.67609
5.5”	Company 1	2-7/8” Packer Style Separator	11.60	14.77	497	480	0.57409
5.5”	Company 1	3.5” Packer Style Separator	8.47	10.79	363	480	0.41927
5.5”	Company 3	3.5” Mother Hubbard	6.03	7.68	258	120	0.07464
5.5”	Company 2	3” Mother Hubbard	6.03	7.68	258	300	0.1866
5.5”	Company 4	2-3/8” Mother Hubbard	2.26	2.88	97		
5.5”	Company 4	2-7/8” Mother Hubbard	3.32	4.23	142		
5.5”	**WellWorx**	**3.75” HALO**	**6.20**	**7.90**	**265**	**240**	**0.15344**
5.5”	**WellWorx**	**4.125” DOMINATOR**	**9.45**	**12.04**	**405**	**240**	**0.23388**
5.5”	**WellWorx**	**1.9” MAX**	**15.09**	**19.22**	**646**	**480**	**0.7458**
5.5”	**WellWorx**	**2-3/8” MAX**	**13.50**	**17.19**	**578**	**480**	**0.6679**
7”	Company 2	4” Mother Hubbard	11.37	14.48	487	300	0.35154
7”	Company 3	4/5” Mother Hubbard	10.57	13.45	452	120	0.13069
7”	**WellWorx**	**1.9” MAX**	**29.90**	**38.07**	**1280**	**480**	**1.47929**
7”	**WellWorx**	**2-3/8” MAX**	**28.31**	**36.04**	**1211**	**480**	**1.40038**
7”	**WellWorx**	**5” HALO**	**13.32**	**16.96**	**570**	**240**	**0.32951**
7-5/8”	Company 2	2-7/8” Packer Style Separator	30.63	39.00	1311	480	1.51543
7-5/8”	**WellWorx**	**3-1/2” MAX**	**27.50**	**35.02**	**1177**	**480**	**1.3606**

Table 2: BHA Design details for WellWorx separator versus industry separators.

For comparison, Table 2 shows standard industry BHA design requirement. The 4.125-inch separator, listed as The Dominator in Table 2, benefits from the largest separation area on the market at 12.04 in^2 with a maximum of 405 barrels/day.

	3.75 Halo	4.125 Dominator
Constant	0.0119	0.0119
Outer Tube ID (in)	3	3.625
Inner Tube OD (in)	1.05	1.05
Cross Sectional Separation Area (in^2)	6.2	9.45
separation area (in^2)	7.9	12.04
Downward Fluid Velocity (ft/sec)	0.4	0.4
Production Limit (BFPD)	265	405

Table 3: Calculation of production limit based on DFV of 0.4 ft/sec.

Table 3 shows how the maximum fluid rate is calculated for a particular separator. Equation 2 is the same as equation 1 but re-ordered to solve Production Limit.

$$\frac{0.4 * (ID_{CSG}{}^2 - OD_{SEP}{}^2)}{0.0119} = Q = Production\ Limit \qquad (2)$$

The standard rate of 0.4 is used to calculate the production limit for both the 3.75-inch Halo and the 4.125-inch Dominator in Table 3. The Halo has a Production Limit of 265 barrels/day while The Dominator has a production limit of 405 barrels/day.

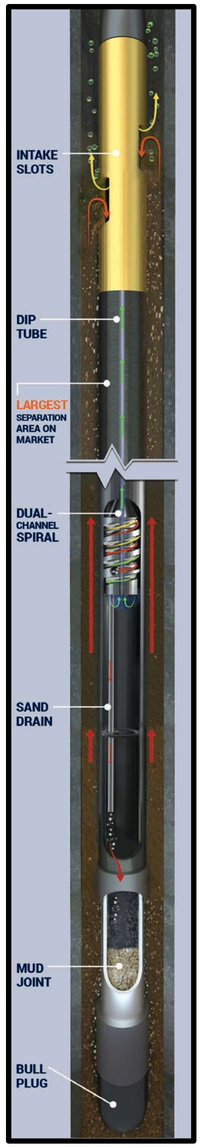

Figure 5: Schematic of the separator

<u>DESIGN OF THE SEPARATOR</u>

The separator includes a dual channel spiral with a solids bypass tube. The body of the tool is 25 feet in length with a 3.625-inch ID and 4.125-inch OD. The top housing body contains four one-foot-wide perforated intake slots. The spiral is one foot long and consists of two flow channels of different pitches. The solids bypass tube is three feet long with a .675-inch OD and an ID of 0.493 inches (3/8-inch nominal OD). Connecting to the top of the centrifuge is a 1.05-inch OD by 19-foot 316SS dip tube. Figure 5 shows a full schematic of the tool.

Metallurgy, wall thickness and erosion mitigation measures ensure tool performance with minimal risk of failure. Wellbore conditions are observed and a nickel-coated option is recommended for corrosive, H2s and other harsh elements.

The sizing and design of the dual-channel centrifuge allows for proper and effective solids separation regardless of production rate. The upper channel uses natural gravity to encourage solids to drop into the lower channel. While in the lower channel, it is extremely difficult for solids to migrate back up into the upper channel. This captures all solids in the lower channel, which then feeds directly into the drain and eventually the solids bypass tube. From there, solids are discharges directly into the mud joints. A full three feet separates the pump intake from the solids discharge point. The solids bypass tube is centered within the tool to prevent a “spoiler” effect, allowing the vortex of fluid to continue around the bypass tube. This allows any solids not captured in the bypass tube to continue the same flow path without disruption, increasing the chances any remaining particles will fall and settle into the mud joints as well.

This separator effectively sumps the pump when a packer-style option is not applicable. By utilizing a large housing body while still maintaining enough clearing from casing, the risk of debris buildup is decreased. The weight of the fluid level above the top cup pushes down on the cup and creates the top seal. This practice is especially important in wells that have already been producing where iron may be present, allowing sufficient space to effectively treat the well.

It was intentionally designed to create the greatest tool OD to casing ID ratio possible, allowing for a maximized cross-sectional separation area in the annulus of the wellbore.

By affixing our internal dip tube to the ID housing, the tool allows for maximum cross-sectional separation area and therefore decreases the downward velocity of the fluid prior to pump entry. As a result, gas is able to escape naturally through the slots and up the casing. The DFV must be slower than the bubble rise velocity for gas separation to occur. Assuming a maximum gas bubble rise velocity of 0.4 ft/sec, the equations previously listed can be used to calculate total pump displacement or barrels of fluid per day that can be effectively separated before “overrunning” the separator. Surpassing that number would cause the downward fluid velocity to exceed the bubble rise velocity and separation efficiencies would be limited.

Figure 6: Structure of the dual-channel spiral.

HOW IT WORKS

In the first step, fluid flows into the intake ports at the top of the tool. Fluid velocity is then decreased to lessen turbulence and emulsion. Gas rises spontaneously and exits the intake slots when fluids and solids are pushed lower.

Once gas-free fluid enters the dual channel spiral, it propels both fluid and particles into a centrifugal motion. Figure 6 illustrates an in-depth look at the spiral. It naturally encourages heavier solid particles to fall into the lower channel while lighter fluids are retained in the higher channel. Solids are then funneled into the solids drain and eventually fall into the solids bypass tube, where they are then deposited into the mud joints. Fluid exits the bottom of the centrifuge and enters the pump suction. [3]

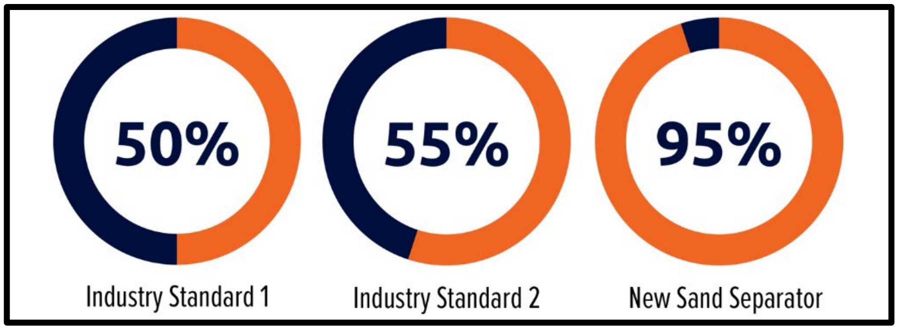

Figure 4: Two industry-standard vortex solids separators compared to the new solids separator.

S VORTEX SAND SEPARATOR CASE STUDY RESULTS

Two industry-standard vortex solids separators as well as the newly developed solids separator component were tested in a well simulator. Solids with different mesh sizes and production rates were also tested. Screen-type separators were excluded from the test because of their propensity to plug off.

The desander component of the new tool operated with an efficiency of 95 percent, a whopping 40 percent higher than the next closest industry standard separator, as shown in Figure 4. These findings are consistent with earlier research, which indicates pumping unit speed and separator design likely causes efficiency to drop below 50 percent.

The various types of gas separators may be simply evaluated through the use of straightforward calculations and the formulae mentioned above. The relationship between the cross-sectional separation area and fluid volume shows how crucial it is to maximize the separation area for higher gas separation efficiency. [3] By taking full advantage of the casing-tubing annulus rather than the tool's dimensional variations, packer-style separators unquestionably produce the largest cross-sectional separation area. Finding the best "packer-less" separation solutions, however, is challenging due to particular wellbore circumstances or operator preferences.

The separator can handle up to 405 BFPD (Production Limit) of fluid volume before separation efficiency start to suffer. Due to the tool's maximum OD, this has a larger fluid volume than any other tool on the current market.

RESULTS & DISCUSSION

In this section, results showing production rates and other key performance indicators (KPIs) before and after installation are presented. KPI data collected includes GLR, pump fillage, strokes per minute (SPM) and runtime. With the exception of Well 1, only production data was available due to automatic data archiving.

In the following production results, gas production is displayed in red, water production in blue, oil production in green and total production in black.

a) Well 1 Results

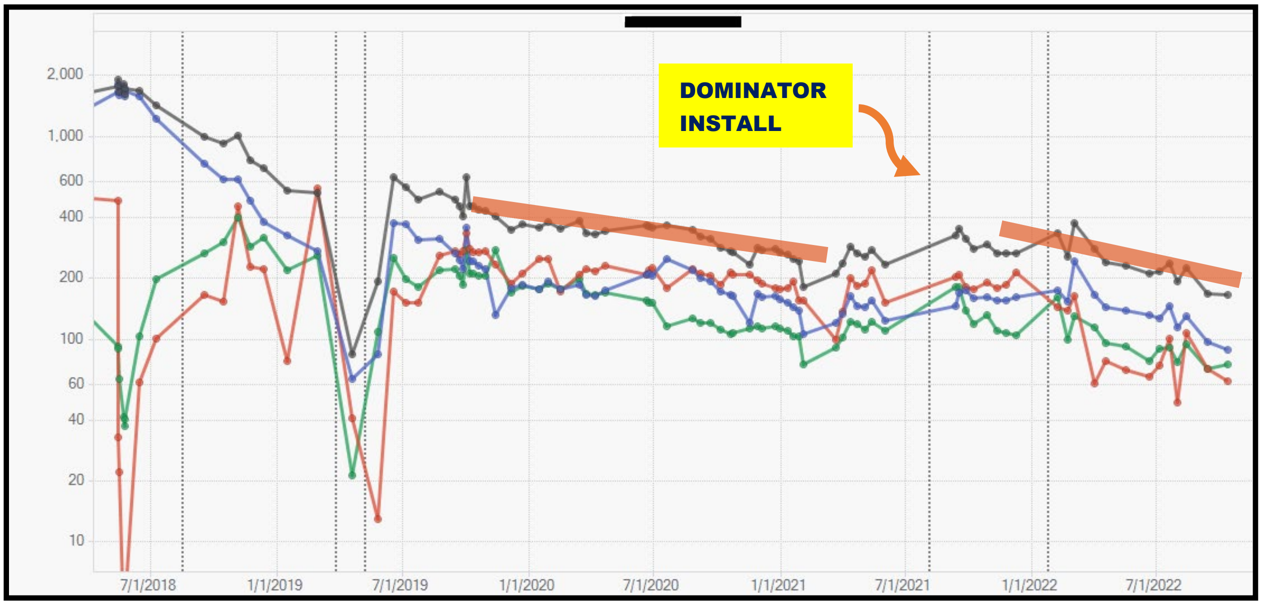

Figure 7 – Production Data from Well 1.

Production increases from 240 to 380 barrels/day can be noted after installation (Figure 7). The thick orange lines highlight the similarity of the decline slope both before and after installation. However, the higher starting point after installation reveals the increase in overall production. The increase in water, along with the decrease in oil and gas incurred due to surrounding well frac offsets.

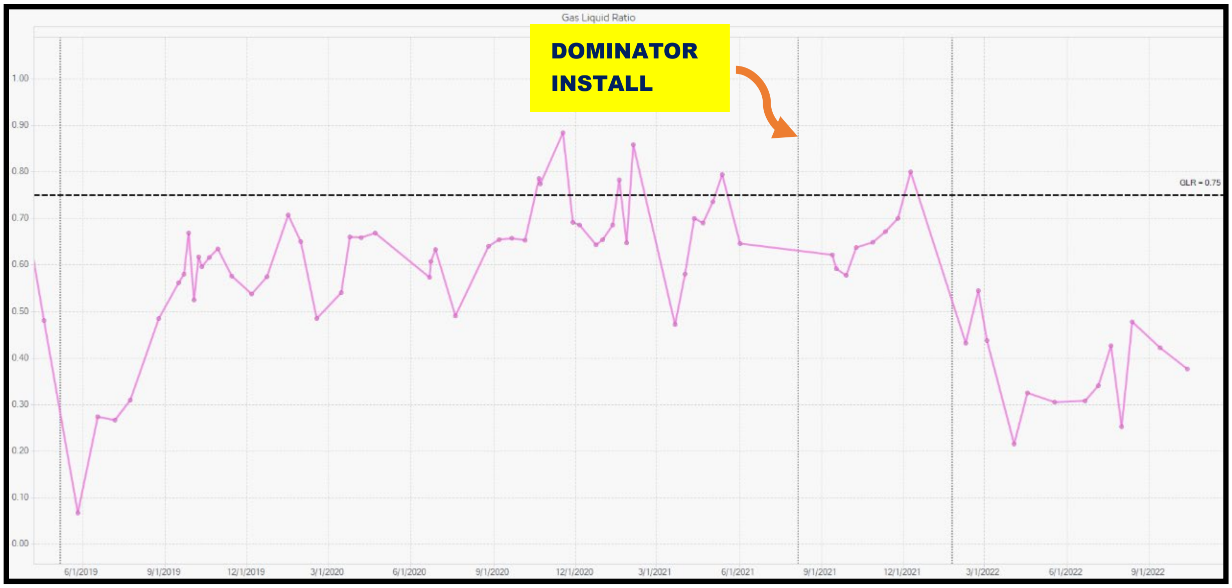

Figure 8 – Gas to Liquid Ratio for Well 1.

As can be seen in Figure 8, the well GLR decreases drastically after installation. The GLR indicates the amount of free gas in produced fluids. A low GLR shows proper gas separation as there is less gas present passing through the pump.

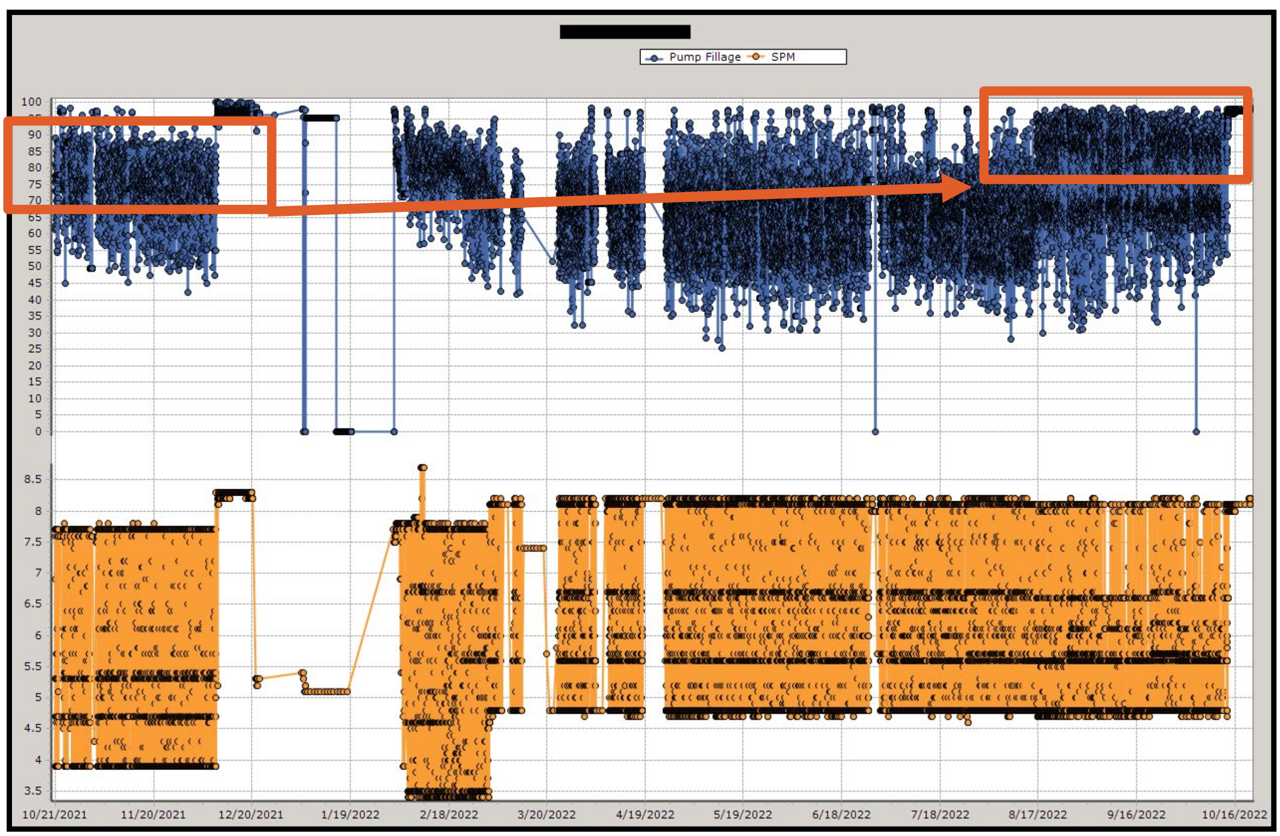

Figure 9 – Pump Fillage and SPM trend for Well 1.

As can be seen by Figure 9, pump fillage (blue) and SPM (orange) trends can be analyzed to offer more clarity on the effectiveness of the tool. The pump fillage for Well 1 was between 60 and 90 percent before installation, suggesting improper gas separation and gas interference related to incomplete fillage. This would result in premature shut down of the controller.

Also notable on the above figure is that as SPM was increased, more gas and erratic pump fillage values would be expected. However, values for pump fillage shows stabilization as well as an overall increase from [60, 90] to [70, 90]. This is highlighted in red in Figure 9.

b) Well 2 Results

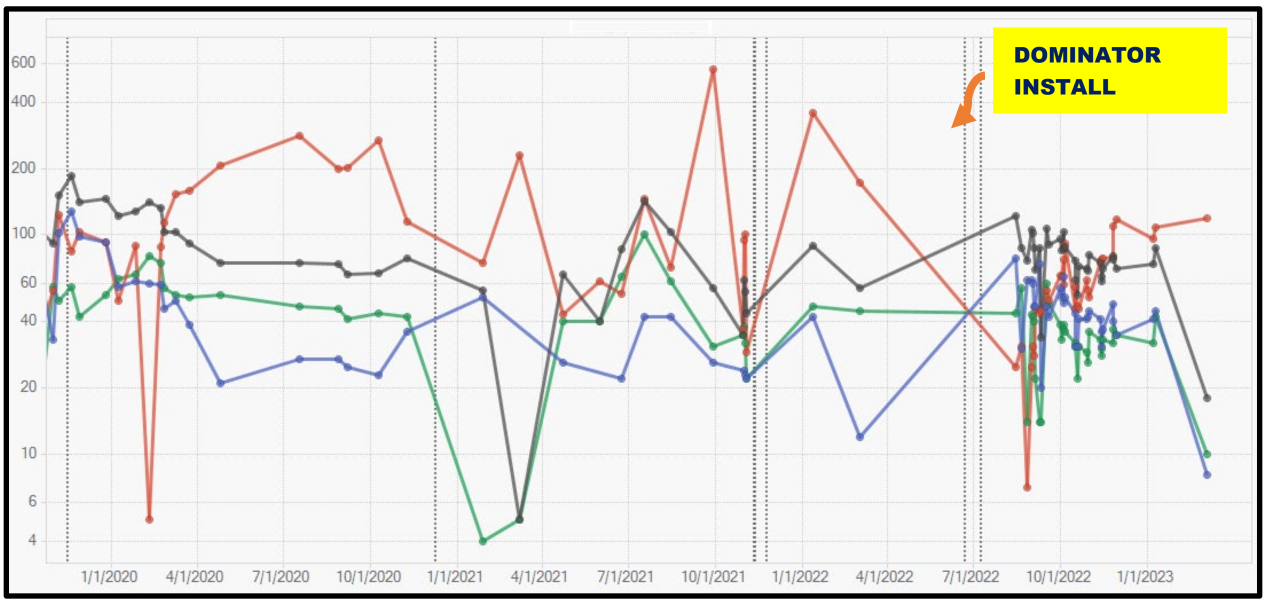

Figure 10 – Production Data from Well 2.

Production data for Well 2 shows sporadic spikes in gas, oil and water production prior to installation. Data seems to follow a more linear behavior with a slight increase in overall production after installation. Notice gas production has drastically increased while oil and water production seem to be less erratic. This is an indicator the well is being drawn down. The decline in production toward the end of the figure comes from loss of pump efficiency due to valve wear.

c) Well 3 Results

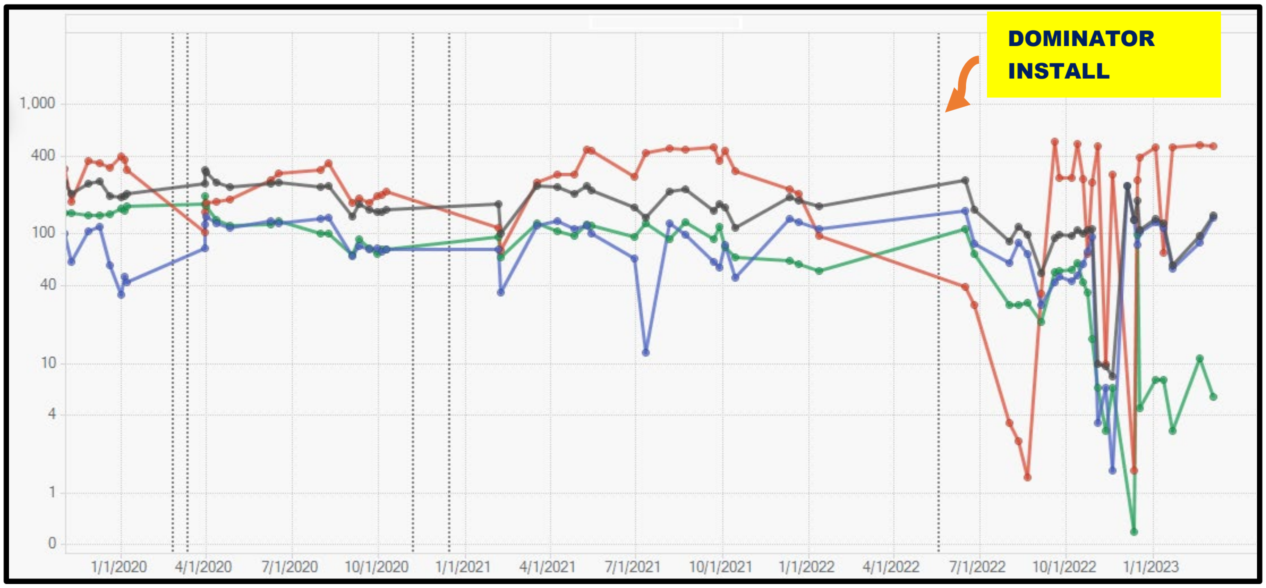

Figure 11 – Production Data from Well 3.

As can be seen from Figure 11, gas production drastically increased after the installation on Well 3. Oil production seems stable after installation while water production shows a decrease. As mentioned above, this is an indicator of drawdown. What is shown here is the well being drawn down for the first time in three years.

d) Well 4 Results

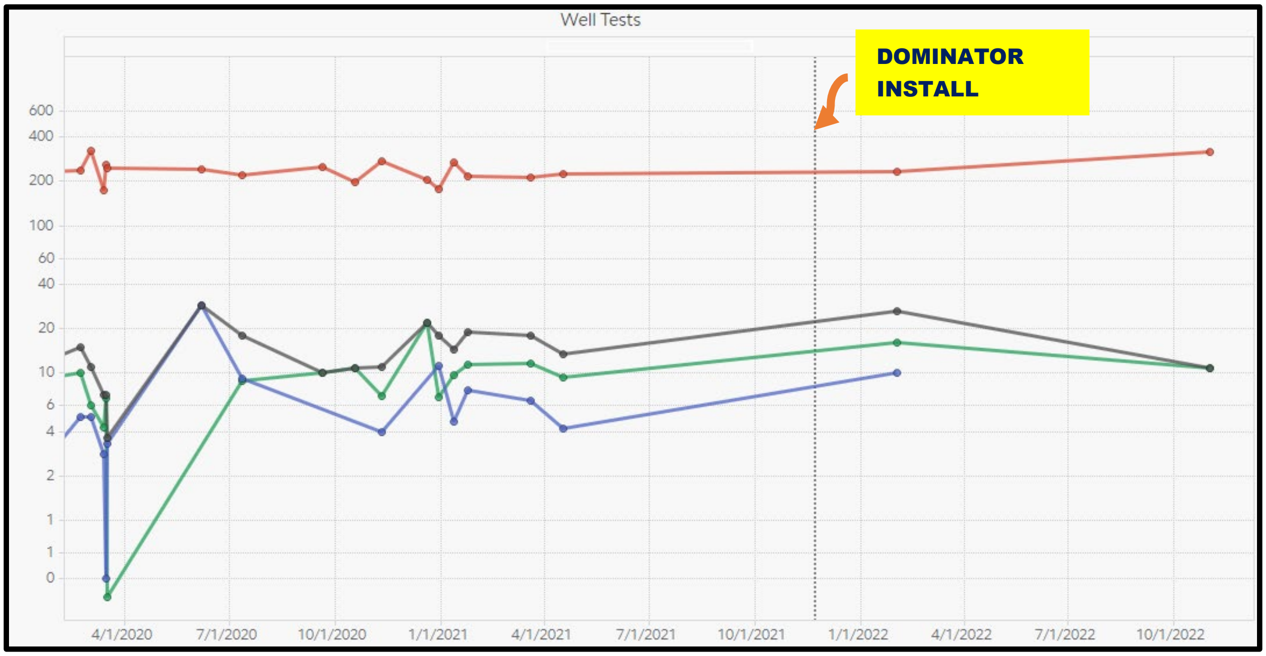

Figure 12: Production Data for Well 4.

Water and oil production shows a significant increase in Figure 12. Additionally, gas production shows a very linear trend with a definite increase after installation. Due to facility constraints and lack of testing, more data was not available for the comparison.

e) Well 5 Results

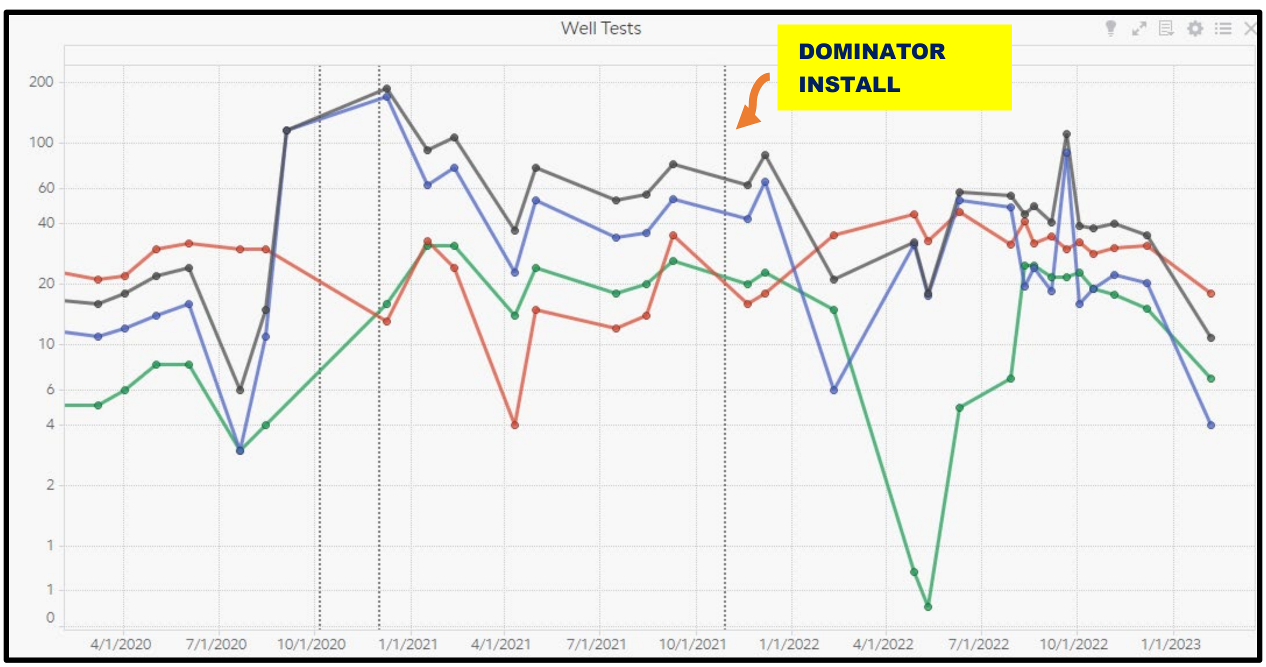

Figure 13: Production Data for Well 5.

Displayed data in Figure 13 shows a steady increase in gas after installation. Oil production shows to be steady compared to before installation except for a drop in oil production from a shutdown May 2022. Water production shows a slight decrease since installation. The steep decline at the end of the production period shown in Figure 13 is caused by loss of pump efficiency from worn standing valve.

The results from Well 5 consistently show either more production or increased gas with less fluids, which is an indicator of drawdown. Both scenarios are what operators should strive for.

Unconventional wells can get stuck in a loop where as soon as the operator attempts to draw down the well, several of the lateral zones unload, which causes gas slugs and potential flumping.

This causes the controller to shut down, which is the last thing the operator should do. Shutting down the controller allows solids and more gas to settle in the anulus. This not only cancels all the drawdown progress made but makes it harder to restart efficient pumping. Once the controller comes back online, the same hydrostatic pressure column as before the well was drawn down remains. In those cases, the operator is perpetually “skimming the top” of available production of the well without ever drawing it down. The results shown prove the wells are efficiently being drawn down using an appropriately sized solid and gas separator.

CONCLUSION

The data presented in this paper shows with proper gas and solid separation, well drawdown is possible. This tool is best suited as a packer-less gas and solids separator option. If reducing sporadic SPM and pump fillage behavior as well as avoiding frequent premature shutdowns is the goal, this separator is an ideal candidate that allows gas to rise naturally. Optimal production is capable with a well thought out BHA design and the use of the proper tool.

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