MANIPULATING CASING PRESSURE TO HANDLE GAS BETTER IN CERTAIN WELL TYPES

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ABSTRACT

Rod pumps are not the ideal artificial lift system when it comes to handling gas. We can only do so much with the downhole configuration, especially for wells with openhole completions. Despite the limited equipment options, we can still manipulate the parameters at the surface. Historically, we have manipulated backpressure on the tubing to control when gas breaks out of solution. On certain well types, manipulating the backpressure on the casing can successfully keep gas in solution through the pump. In so doing, beam-pumped wells now experience less equipment stress due to gas interference, exhibit more consistent and stable production, and even have optimized inflow resulting in increased production.

IDEAL CANDIDATES FOR CASING CHOKES

Historically, adding pressure to the casing on beam-pumped wells has been avoided because it restricts inflow and production across the board. That may be true for most wells, but we have found that certain wells with gas handling difficulties actually benefit from adding pressure to the casing. **Figure 1** shows one such well's runtime before and after installing the choke. Theoretically, in a steady-state reservoir, flow into a reservoir should equal flow out of a producing well. Producing wells installed with automation that tracks loads and positions based on pump fillage should not be running 18 hours one day and 8 hours the next, assuming no drastic injection changes or other significant equipment issues. After we installed a manual casing choke, the runtime immediately increased and became more consistent, like a steady-state reservoir beam well should be.

Along with erratic runtime, **Figure 2** shows a well that has erratic cycle times, defined as the amount of time the unit runs when it kicks back on. This parameter is key, because it confirms whether a beam well is falsely pumping off. A well running 2 hours for one cycle and 23 minutes for the next cycle is not a steady-state reservoir. After the choke was installed and the casing pressure was increased by 50 psi, cycle times for this well became more stable, generally around 50 minutes to an hour.

The next, and most important, question that must be asked is: What happened to production? **Figure 3** shows the oil production before and after installing the choke. On average, oil production increased, and total fluid volume became more consistent and increased as well. The reason is that when false pump-offs due to gas interference are minimized, bottomhole pressure is also minimized, allowing more fluids to enter the wellbore and ultimately be produced. False pump-offs leave a fluid level remaining above the pump, and the unit shuts down for its determined idle time. During this idle time, the wellbore does not fill back up because the fluid level above the pump exhibits hydrostatic pressure that limits the inflow. Eliminating these false pump-offs eliminates the fluid above the pump and its hydrostatic head on the well during idle time. This allows more fluid to flow into the wellbore and increases production. It also creates a more consistent baseline for well performance, as would be expected in a steady-state reservoir with consistent injection.

Although it seems counter-intuitive, adding pressure to the casing in such circumstances actually increased production and made it more consistent. We have found this concept to work for multiple wells, but it is not a universal law; it works on a case-by-case basis. An ideal candidate well would exhibit erratic runtime, erratic cycle intervals, and stable casing flow and pressure. **Figure 4** demonstrates the difference between erratic and stable casing flow and pressure. We use chart recorders on the casing for 24 hours to determine what type of flow behavior is coming up the casing. If it is relatively stable, this makes it an ideal candidate for a manual choke, assuming it has the other two symptoms. If it is erratic, it is best to leave the well alone, because it would not be possible to control the casing pressure effectively. Automated chokes give you the flexibility to deal with erratic casing pressure as discussed in the next section.

AUTOMATED CHOKES

As this project progressed, automated chokes seemed suitable for future candidates to improve efficiency. With automated chokes, the casing pressure can be monitored from the office. Casing pressure can be set for the automated choke to regulate the well, and any changes that occur at the well, such as a slug of gas up the casing, can be mitigated and often controlled with an automated choke.

Figure 5 shows the progression of cards in a single cycle as the casing pressure is increased by an automated choke. When the casing pressure was 70 psi, the pump had 70% pump fillage. When the casing pressure increased by 20 psi to 90 psi, the pump fillage increased to 90%. This is significant when considering equipment stress and the ability to pump in various gassy conditions.

Without automation, somebody would have to check up on the well to make sure the pressure was on target and to adjust the choke. With automation, these adjustments take place in the office, and they can take effect almost immediately. Automation adds efficiency and better control of the casing pressure and results in better performance for beam-pumped wells.

Figure 6 and **Figure 7** show the changes after the manual and automated chokes were installed for a specific well. After the installation of the manual choke, production and runtime generally declined, because there was too much casing pressure on the well. The manual choke was unable to control the casing pressure as well as we would have liked. After installing the automated choke, the casing pressure became easier to control, allowing us to fine-tune the casing pressure and find the “sweet spot” for this well to run most effectively. Overall, automation allows better control of the casing pressure without having to send someone out to the well multiple times a day. The automation also allows adjustments to occur immediately when casing pressure deviates from a setpoint or if someone wants to make a setpoint change to the well. This significantly increases the overall effectiveness of manipulating casing pressure on beam-pumped wells and expands the choke candidates to wells that have more variability in casing pressure and flow.

CONCLUSION

Manipulating the casing pressure on certain beam-pumped wells has proven to be effective in achieving more consistent production and runtimes, while in some cases also increasing production by minimizing false pump-offs caused by gas interference. Adding too much casing pressure to the well can have negative consequences on production due to restricting the inflow into the wellbore, but finding the “sweet spot” for the casing pressure can improve well performance. While this is possible with manual chokes, automated chokes make it much easier to find that sweet spot and maintain it, as shown by the examples discussed above. Casing chokes are not a permanent fix for problems caused by installing improper gas handling equipment, but the concept is definitely something to consider when dealing with erratic runtime wells that have been deemed problem wells.

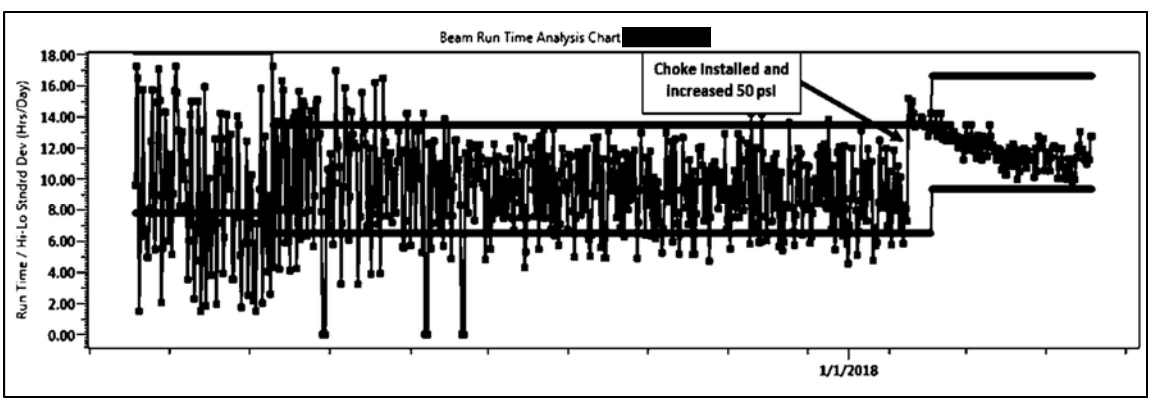
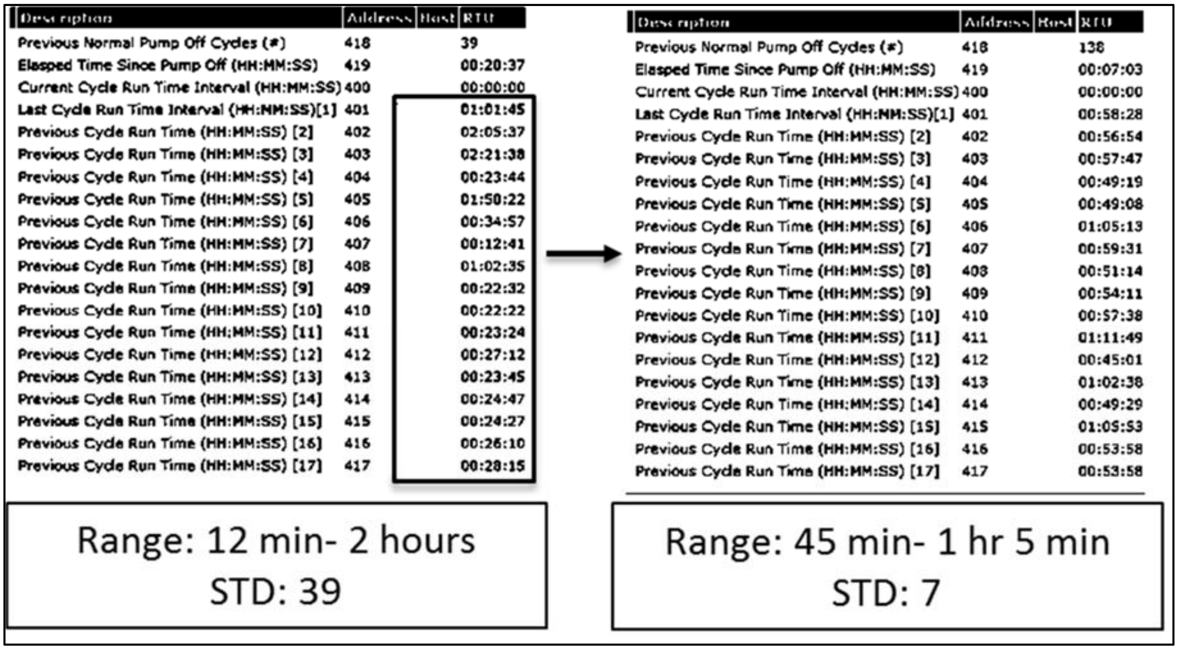


Figure 1: Runtime of this well before and after installing the manual casing choke



Description	Address	Host	RTU
Previous Normal Pump Off Cycles (#)	418		39
Elasped Time Since Pump Off (HH:MM:SS)	419		00:20:37
Current Cycle Run Time Interval (HH:MM:SS)	400		00:00:00
Last Cycle Run Time Interval (HH:MM:SS)[1]	401		01:01:45
Previous Cycle Run Time (HH:MM:SS) [2]	402		02:05:37
Previous Cycle Run Time (HH:MM:SS) [3]	403		02:21:38
Previous Cycle Run Time (HH:MM:SS) [4]	404		00:23:44
Previous Cycle Run Time (HH:MM:SS) [5]	405		01:50:22
Previous Cycle Run Time (HH:MM:SS) [6]	406		00:34:57
Previous Cycle Run Time (HH:MM:SS) [7]	407		00:12:41
Previous Cycle Run Time (HH:MM:SS) [8]	408		01:02:35
Previous Cycle Run Time (HH:MM:SS) [9]	409		00:22:32
Previous Cycle Run Time (HH:MM:SS) [10]	410		00:22:22
Previous Cycle Run Time (HH:MM:SS) [11]	411		00:23:24
Previous Cycle Run Time (HH:MM:SS) [12]	412		00:27:12
Previous Cycle Run Time (HH:MM:SS) [13]	413		00:23:45
Previous Cycle Run Time (HH:MM:SS) [14]	414		00:24:47
Previous Cycle Run Time (HH:MM:SS) [15]	415		00:24:27
Previous Cycle Run Time (HH:MM:SS) [16]	416		00:26:10
Previous Cycle Run Time (HH:MM:SS) [17]	417		00:28:15

Range: 12 min- 2 hours
STD: 39

Description	Address	Host	RTU
Previous Normal Pump Off Cycles (#)	418		138
Elasped Time Since Pump Off (HH:MM:SS)	419		00:07:03
Current Cycle Run Time Interval (HH:MM:SS)	400		00:00:00
Last Cycle Run Time Interval (HH:MM:SS)[1]	401		00:58:28
Previous Cycle Run Time (HH:MM:SS) [2]	402		00:56:54
Previous Cycle Run Time (HH:MM:SS) [3]	403		00:57:47
Previous Cycle Run Time (HH:MM:SS) [4]	404		00:49:19
Previous Cycle Run Time (HH:MM:SS) [5]	405		00:49:08
Previous Cycle Run Time (HH:MM:SS) [6]	406		01:05:13
Previous Cycle Run Time (HH:MM:SS) [7]	407		00:59:31
Previous Cycle Run Time (HH:MM:SS) [8]	408		00:51:14
Previous Cycle Run Time (HH:MM:SS) [9]	409		00:54:11
Previous Cycle Run Time (HH:MM:SS) [10]	410		00:57:38
Previous Cycle Run Time (HH:MM:SS) [11]	411		01:11:49
Previous Cycle Run Time (HH:MM:SS) [12]	412		00:45:01
Previous Cycle Run Time (HH:MM:SS) [13]	413		01:02:38
Previous Cycle Run Time (HH:MM:SS) [14]	414		00:49:29
Previous Cycle Run Time (HH:MM:SS) [15]	415		01:05:53
Previous Cycle Run Time (HH:MM:SS) [16]	416		00:53:58
Previous Cycle Run Time (HH:MM:SS) [17]	417		00:53:58

Range: 45 min- 1 hr 5 min
STD: 7

Figure 2: Time between each idle period indicating how long the unit ran until it pumped off again

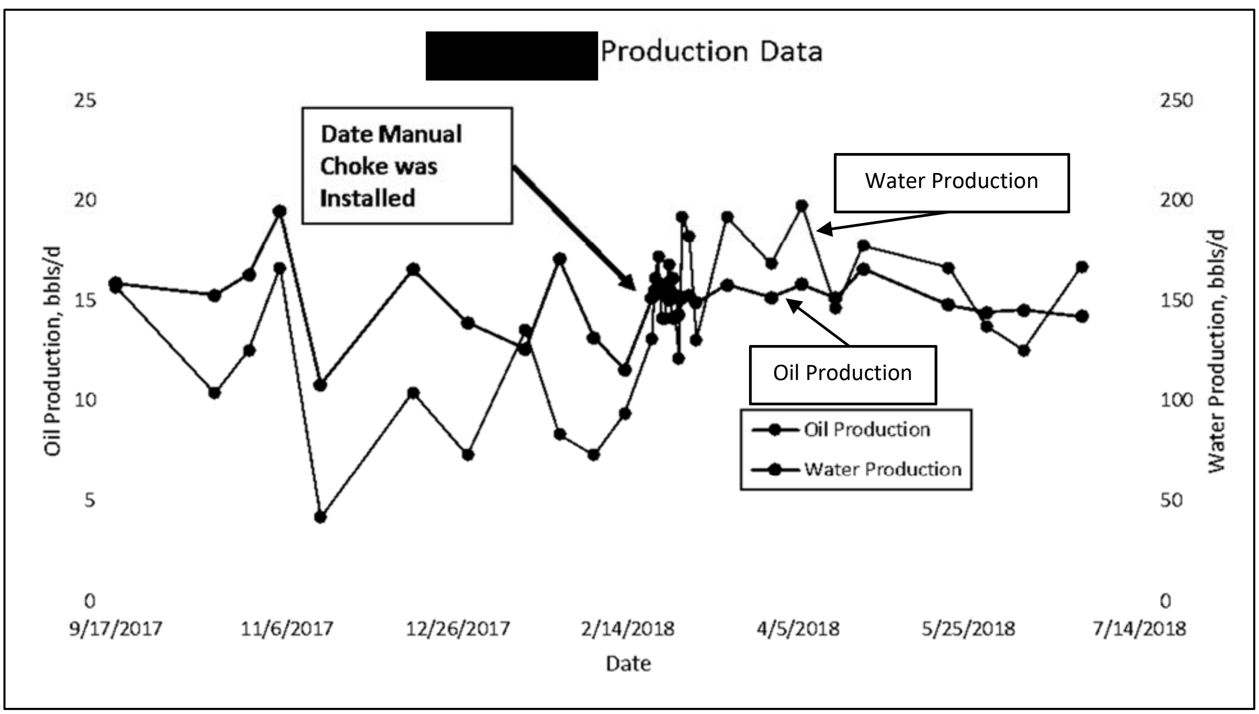


Figure 3: Production data before and after installing the casing choke and the resulting increase in oil production and consistency in water production

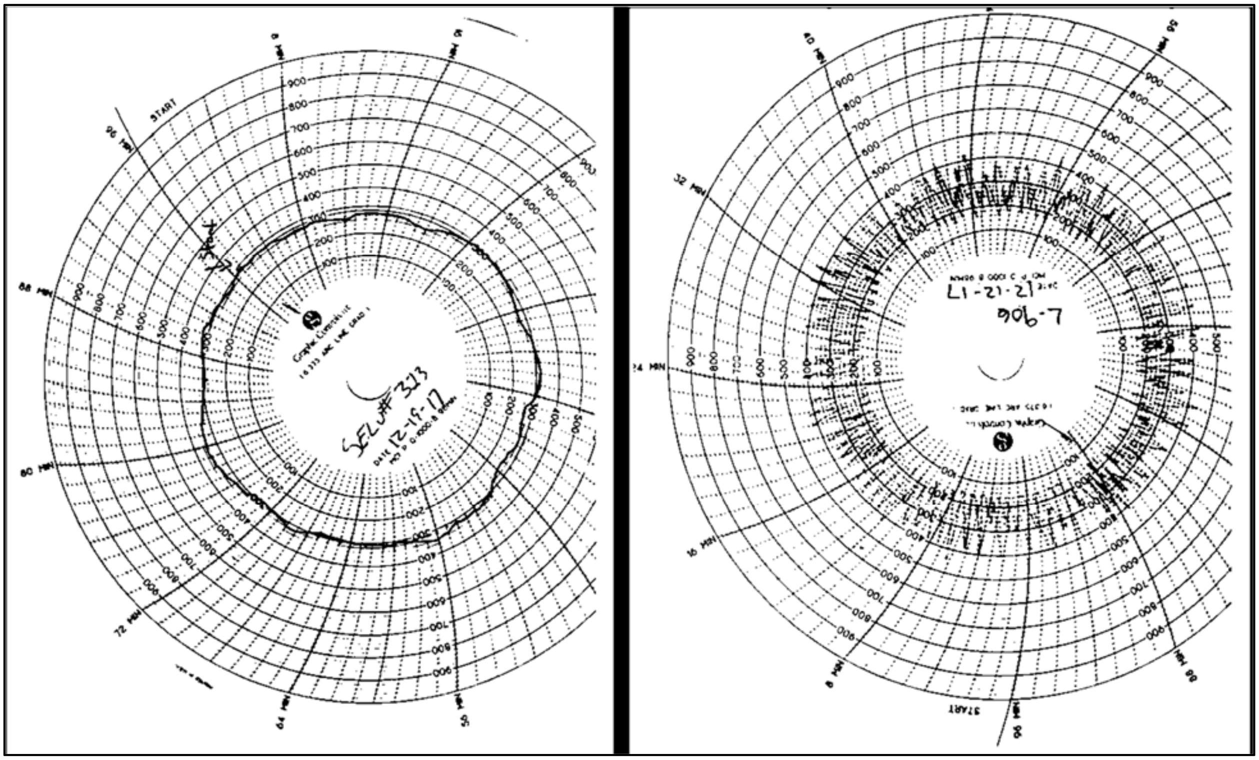


Figure 4: Ideal casing flow conditions (left) and non-ideal casing conditions (right) that make it harder to control casing pressure with a manual choke.

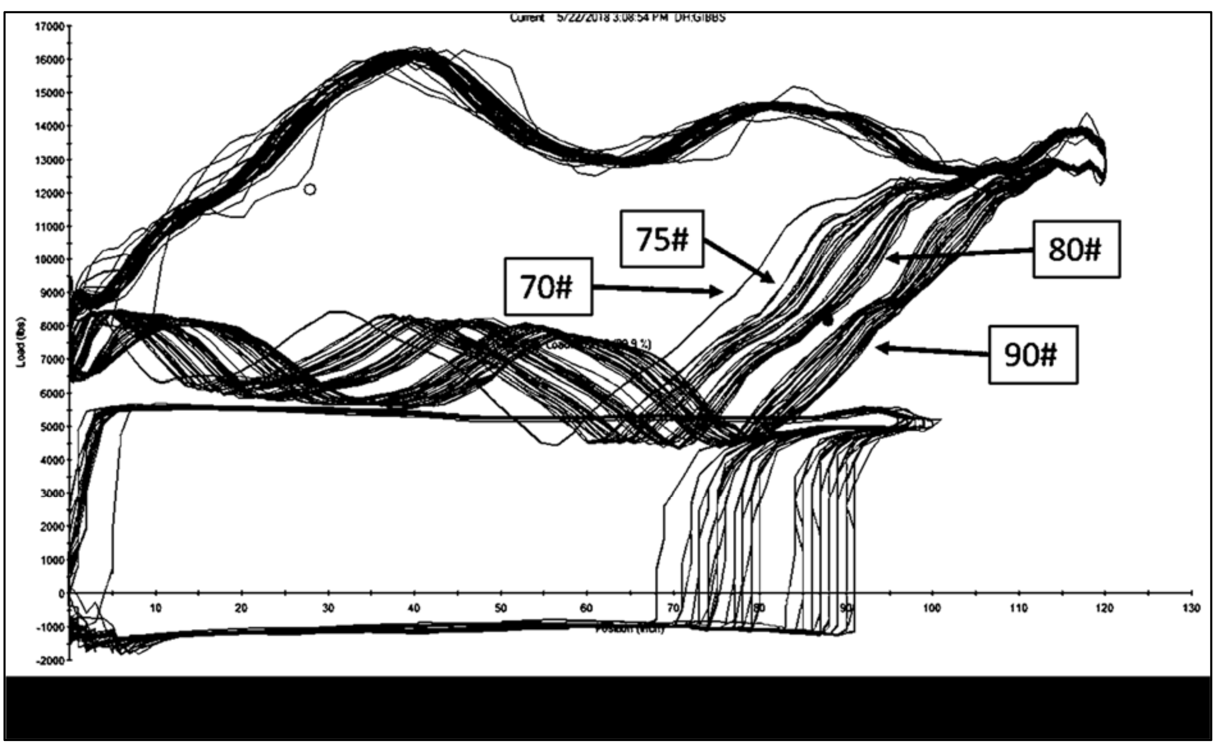


Figure 5: Progression of cards as casing pressure was increased; the cards filled out, indicating less gas interference.

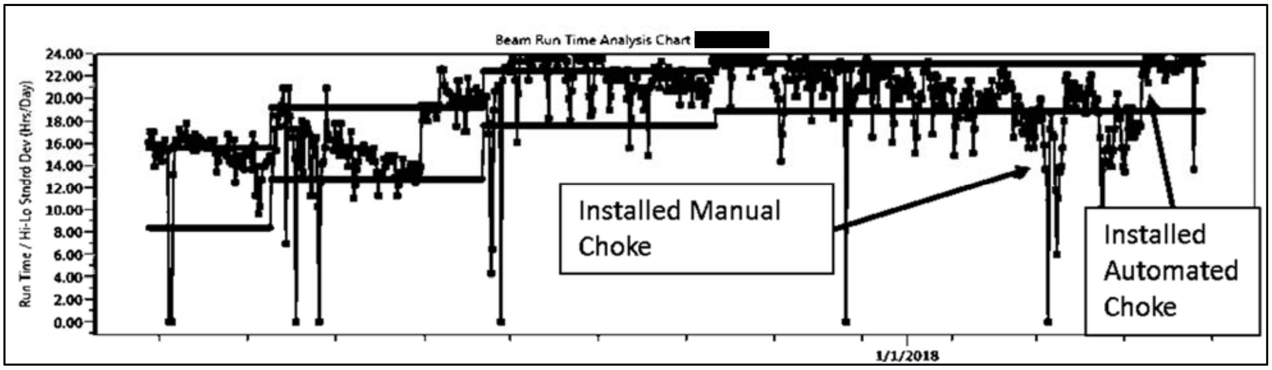


Figure 6: Runtime before and after the manual choke and automated choke were installed

*Well Name	Separator	^Date	Oil	Water	Total Fluid	Total Gas	% DH Pump Eff.	SPT Code	WellTest Bad Reason Code	Comments	Pumping (Hrs)	Strokes /Min
			stb/d	stb/d	stb/d	mscf/d	%					
Mean			9.15	70.17	79.32	391.50	58.58	0.00			20.71	8.17
[redacted]	[redacted]	07/05/2018	12.48	77.98	90.46	419.01	61.76	0			22.32	8.14
[redacted]	[redacted]	06/27/2018	15.65	73.04	88.70	403.83	56.53	0			24.00	8.13
[redacted]	[redacted]	06/23/2018	14.61	69.91	84.52	469.56	54.28	0			24.00	8.14
[redacted]	[redacted]	06/15/2018	6.26	75.13	81.39	430.95	52.18	0			23.52	8.14
[redacted]	[redacted]	06/11/2018	5.45	61.09	66.55	452.73	56.42	0			17.52	8.15
[redacted]	[redacted]	05/21/2018	7.28	56.15	63.42	528.18	56.51	0			17.28	8.15
[redacted]	[redacted]	05/04/2018	10.43	57.39	67.83	485.22	54.94	0			18.72	8.16
[redacted]	[redacted]	04/02/2018	6.26	68.87	75.13	462.26	59.84	0			19.20	8.15
[redacted]	[redacted]	03/18/2018	11.48	66.78	78.26	440.35	59.48	0			20.16	8.16
[redacted]	[redacted]	02/13/2018	8.15	73.36	81.51	410.26	62.85	0			19.92	8.17
[redacted]	[redacted]	01/10/2018	8.32	71.76	80.08	396.26	59.56	0			20.40	8.16

Avg. 14.25 BOPD
Avg. 87 BTFD

Avg. 7.3 BOPD
Avg. 70 BTFD

Avg. 8.6 BOPD
Avg. 78.7 BTFD

Figure 7: Production before and after the manual and automated chokes were installed