ENHANCING PRODUCTION IN PERMIAN OIL WELLS USING ACID DIVERTER

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ABSTRACT

As wells decline and available acreage for new wells lessens in the Permian Basin, it becomes increasingly important that operators capitalize on existing wells to maximize reserves. Scaling is a known issue in the basin, and this paper will address a potential solution. Acid treatments have proven to be effective across different applications, and the effectiveness has potential to increase significantly when diverter is included. The operator has taken the approach of pumping acid diverter jobs during workover when there is significant concern of restrictions due to acid dissolvable scaling in the wellbore.

INTROUDUCTION AND PROBLEM STATEMENT

The Permian Basin operator explored long-term solutions after experiencing repeated short-term success with pumping 15% HCl down production equipment to address acid-soluble scaling. Prior to implementing the new program, typical jobs involved the engineer and artificial lift technician collaborating to pump 300-1000 gallons of 15% HCl, preceded by 2-3 barrels of solvent to remove non-acid soluble substances. These acid jobs were pumped down tubing and spotted either at the motor of an ESP or at the top perforations.

METHODOLOGY

The program began with a well that had achieved significant temporary uplift from the acid flushes down the ESP. These small acid jobs were performed every 4-5 weeks following the well declining dramatically in its first 200 days since bringing online from over 4000 BFPD to 1000 BFPD. The fluid rate drop coordinated with a massive drop in intake pressure from around 1500 psi to less than 200 psi. There was typically a stair-step trend in production observed following these small acid jobs that would get production near 1500 BFPD at 400 psi intake pressure (Figure 1).

The ESP was pulled proactively due to observing this continuous recurring restriction of inflow to perform an acid diverter job and downsize the ESP to better fit the new flowrate and well conditions of the well. An acidizing company assisted with information and suggestions for the acid diverter job and tested the produced liquids to ensure an effective recommendation could be made.

The volumes of hydrochloric acid and chemical additives for acidizing treatments were determined by analyzing key parameters, including the pay zone interval, wellbore integrity, bottomhole pressure, scaling potential, formation wettability, and historical production data. Laboratory acid compatibility testing was then conducted, incorporating these variables to design and validate the most effective acid system for optimal reservoir stimulation and treatment efficiency. These tests are crucial before acid treatments are pumped to prevent formation damage caused by sludging and emulsions resulting from the interaction of live acid, crude oil, and ferric iron downhole.

To ensure that acid systems do not cause formation damage, a detailed acid compatibility test is conducted before pumping stimulation treatments. During testing, liquid iron stock was added to the acid system to simulate downhole conditions, with the sample tested at a bottom-hole temperature of 150°F (Table 1). Downhole, ferric iron combined with live acid and crude oil can lead to emulsions and precipitate sludge, potentially blocking producing zones.

The initial acid compatibility test revealed that the first acid system failed because the iron control agent did not adequately prevent emulsification between the crude oil and acid system, leading to crude oil sludge precipitation (Figure 2). A second acid system was tested, incorporating an iron-reducing agent along with an anti-sludge surfactant. This formulation successfully achieved phase separation between the oil and acid system within three minutes while preventing crude sludge precipitation (Table 2 / Figure 3). Additional analysis was conducted to verify a well-defined interface between the acid system and the crude oil sample, ensuring accurate characterization of formation wettability through interaction with a corresponding formation water/crude oil sample (Table 3).

The acid system was specifically designed to address various wellbore conditions. It effectively removes oil- and paraffin-coated scale/carbonate deposits and breaks down downhole emulsions using Petrosol, a multipurpose acid intensifier surfactant. Laboratory testing confirmed the need for an iron-reducing agent combined with an anti-sludge agent to prevent crude oil sludge formation. Additionally, an iron sulfide dispersant was incorporated to break down large aggregate deposits of iron sulfide scale. To ensure the protection of tubulars from corrosion, a corrosion inhibitor was applied and adjusted to bottom-hole temperature (Table 4).

Diversion techniques in acid stimulation treatments are critical for optimizing fluid distribution across the pay zone of oil and gas wells, preventing premature fluid breakthrough at the initial perforations, and enhancing overall treatment efficacy. Historically, rock salt served as the primary diversion agent for short vertical pay zones. However, with the industry's shift toward stimulating extended lateral pay zones, achieving efficient, controlled, and cost-effective diversion has become increasingly complex due to the greater variability in formation properties, fluid dynamics, and perforation cluster efficiency.

To address the challenges associated with acid stimulation in horizontal wells, various diversion techniques have been implemented to enhance treatment efficiency. These diversion methods are broadly categorized into mechanical and chemical approaches. Mechanical diversion techniques, such as pinpoint injection, plug-and-packer systems, ball sealers, perf pods, rock salt, and polylactic acid, often present operational constraints or increased costs. Conversely, chemical diversion methods, including gelled acid systems, exhibit limitations in effective diversion due to viscosity constraints that hinder their ability to adequately seal pay zones, reducing treatment uniformity and overall stimulation effectiveness.

To identify a reliable and cost-efficient diversion method, a comprehensive analysis of various processes is required. First, diversion techniques must be evaluated through acid stimulation treatment reports to quantify their diversion effectiveness and operational impact. Second, a detailed cost-benefit analysis of each diversion method must be conducted to ensure economic feasibility. Third, formation damage evaluations should be carried out using stringent quality control protocols to ensure that the diversion method does not induce any downhole complications that could adversely affect reservoir performance or production rates.

Various diversion materials can induce formation damage under certain conditions. The use of rock salt for diversion in horizontal wells poses the risk of salt bridging at the heel of the lateral, potentially obstructing flow and impeding effective stimulation. Pin Point Injection (PPI) treatments in horizontal wells introduce a risk of tool failure, with PPI tools becoming stuck within the lateral sections, leading to costly fishing operations. Chemical gel systems can present challenges in terms of their incomplete breakdown, potentially leading to unintended sealing of productive zones and restricting production. Additionally, polylactic acid (PLA) diversion materials may fail to degrade adequately in lower-temperature wells due to thermal degradation constraints, limiting their effectiveness in such environments.

ONSITE OPERATIONS

Well A employed 5 stages, each using 24 bbl. gel pills, and achieved an average pressure increase of 390 PSI per stage. Furthermore, pressure recovery after a shutdown at the end of the job remained stable during the post-flush, suggesting further that acid was effectively diverted in the wellbore (Figure 4).

Well B incorporated 7 stages, each using 20 bbls gel pills, and achieved an average pressure increase of 2,014 PSI per stage. Stabilized pressure throughout flush volume further indicates acid was diverted in the wellbore (Figure 5).

Scenario 3 used 5 stages of 24 bbl. gel pills and averaged a 630 PSI pressure increase per stage. Notably, pressure increases during the post-flush indicated that acid was successfully diverted in the wellbore (Figure 6).

SUMMARY AND FUTURE WORK

From the six horizontal diversion treatments, it was consistently observed that the gel pills demonstrated significant stage pressure increases. Following a comprehensive assessment of diversion materials employed in horizontal acid treatments, freshwater gel pills have demonstrated consistent diversion capabilities in horizontal wells, while also proving to be the most cost-effective method. Prior to deployment, extensive quality control procedures were conducted in the laboratory to evaluate all chemical additives involved in the gel pill formulation. These tests ensured that the gel achieved consistent optimal viscosity and density, with the formulation also incorporating a time-released breaker to facilitate the complete degradation of the gel to water (Figure 7). Since 2024, freshwater gel pills have been commonly used as a diversion technique in 205 horizontal acid stimulation treatments, consistently delivering reliable and predictable diversion and production outcomes. Consequently, this method has become the preferred choice for many operators in the Permian Basin.

The acid diverter job on Well A improved total production from a pre-job 30-day average of 1200 BFPD at 220 psi to a post-job 30-day average of 2140 BFPD at 595 psi, allowing for a 211 BOPD uplift (Table 6). At the 200-day mark following the job, this well was still sustaining around a 100 BOPD uplift in comparison to the pre-job 30-day average (Figure 8 / Table 7). The success of this job was quickly noted post return to production and the program to treat more wells began.

Of the six well sample set from 2024, two additionally had mechanical lateral cleanouts. Looking at the 30-day pre-to-post oil uplift of all six wells, the average oil uplift is at 189%. These horizontal wells range across four different benches – Jo Mill, Lower Spraberry, Leonard, and Wolfcamp A. Looking at an average of 200 days elapsed time from workover, 116% average oil uplift is still observed, prompting that the acid diverter jobs have a long-term effect on productivity.

Other jobs pumped have insufficient days post return to production or faced significant curtailment post-workover, making it difficult to be considered in the study. Based on results thus far, the acid diverter program has been considered a success and candidates will continue to be added as seen necessary by respective production engineer.

Table 1: Test information

Test Information	
Total amount of acid and crude tested: 100 ml	BHT Tested: 150
Acid emulsion test type: Oil/Acid	Acid sludge test type: Live

Table 2: Phase separation between acidizing fluid and crude oil sample (non-emulsification)

Time	Breakout (ml)	Breakout (%)	Iron Amount 10000 PPM
1 min	20 ml	40%	Iron Type FE2/FE3
2 min	40 ml	80%	Iron Ratio 3/1 10,000 PPM
3 min	50 ml	100%	
Remarks	Broke out in 3 min 100%, no sludge. Recommended blend		

Table 3: Pass / fail criteria for selecting additives.

Performance		
Area	Passed	Failed
Blend prior		X
Breakout	X	
Interface	X	
Wettability	X	
Low Surf.	X	
Sludging	X	
Other	X	

Table 4: Additives tested for Well A diverter job.

Additives Tested	Description	Amount Tested
I8	Corrosion Inhibitor	4 GPT
IC200	Iron Control	3 GPT
4% Petrosol	Acid Intensifier	40 GPT
FEGREEN	Iron Sulfide Dispersant	4 GPT
FEAS2X	Anti-Sludge	6 GPT

Table 5: Diversion Breakdowns

Well	Diversion Type	Stages	Amount Per Stage	Total Amount
A	Gel Pills	5	24 bbl	5,000 gal
B	Gell Pills	7	20 bbl	6,000 gal
C	Gel Pills	5	24 bbl	5,000 gal

Table 6: Production and intake pressure "uplift" from 30 days pre- to post- workover. Note: Red font indicates the 2 wells that additionally had lateral cleanouts.

Well	Uplift at 30 Days RTP					
	BOPD	BWPD	MCFD	PIP	BFPD	Incremental Oil Uplift Percentage
A	211	731	320	750	942	318%
B	209	727	380		937	458%
C	34	180	2		215	57%
D	65	294	191	506	360	199%
E	55	361	203	13	416	93%
F	4	141	-176	387	145	11%

Table 7: Production and intake pressure "uplift" from 30 days pre- to 200 days post- workover. Note: Red font indicates the 2 wells that additionally had lateral cleanouts.

Well	Uplift at Average 200 Days RTP					
	BOPD	BWPD	MCFD	PIP	BFPD	Incremental Oil Uplift Percentage
A	101	465	411	374	565	152%
B	131	-137	300	636	-6	286%
C	42	83	478	0	125	70%
D	26	511	11	-65	537	44%
E	42	189	302	439	231	130%
F	6	194	-89	359	200	17%

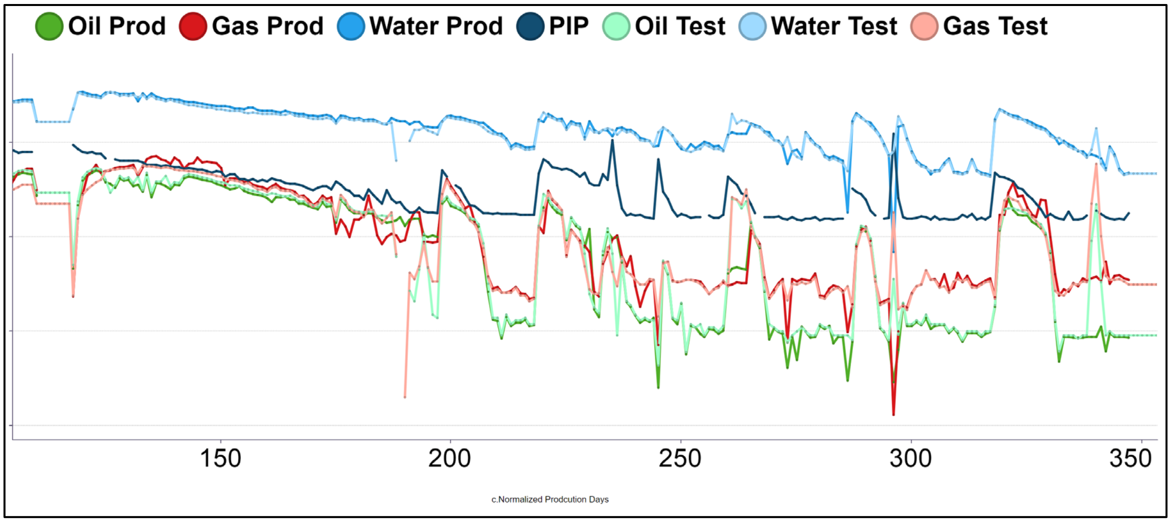

Figure 1: Well A production and intake pressure plot vs normalized days from signs of scaling to point of workover.

Figure 2: Failed blend.

Figure 3: Recommended blend.

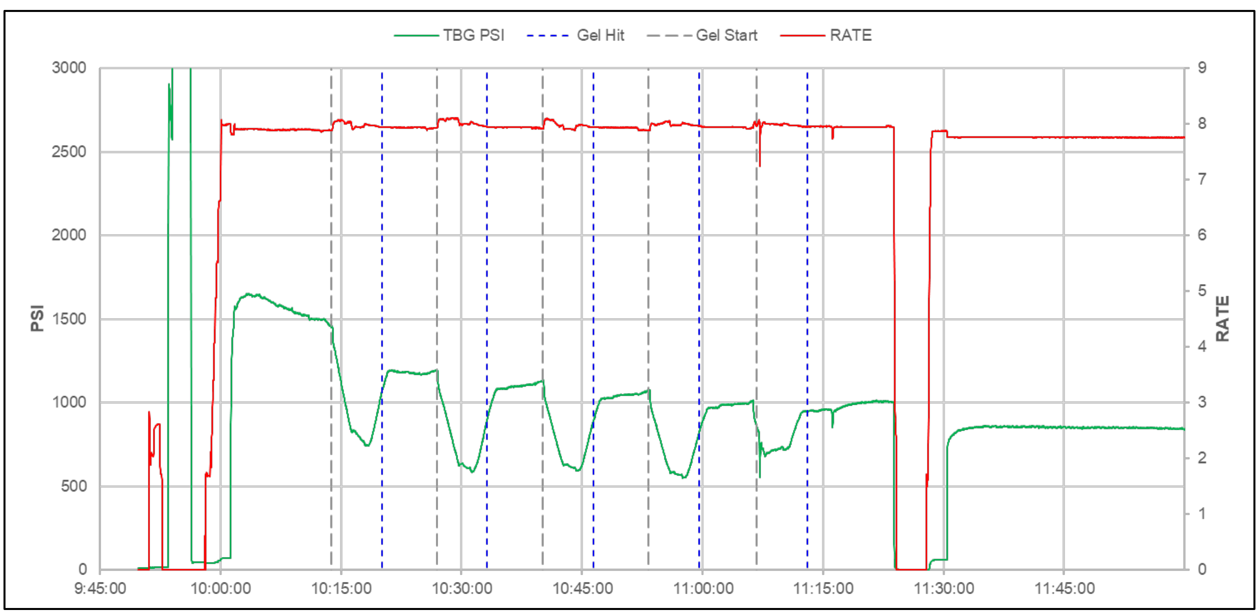

Figure 4: Well A Gel Pill Diversion Breakdown

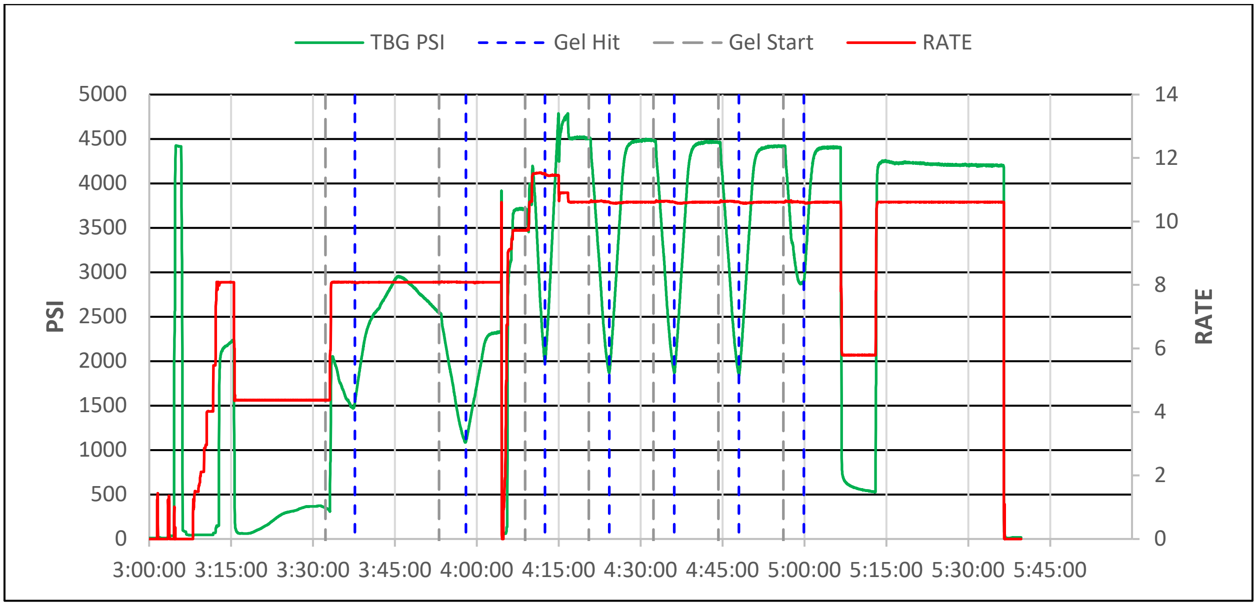

Figure 5: Well B Gel Diversion Breakdown

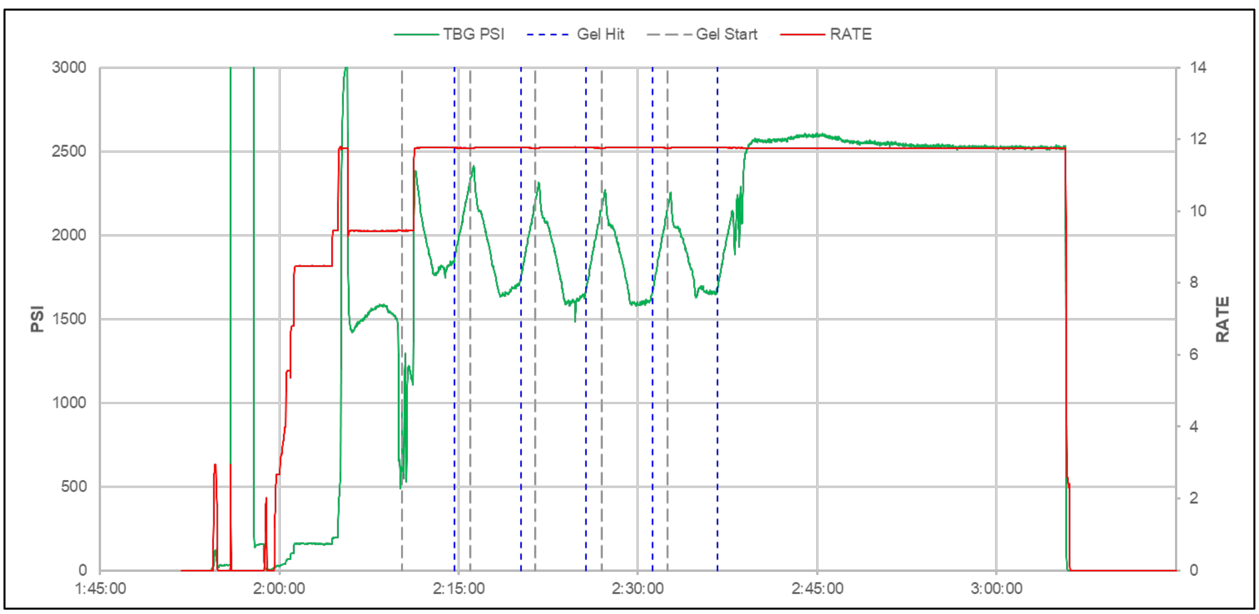

Figure 6: Well C Gel Pill Diversion Breakdown

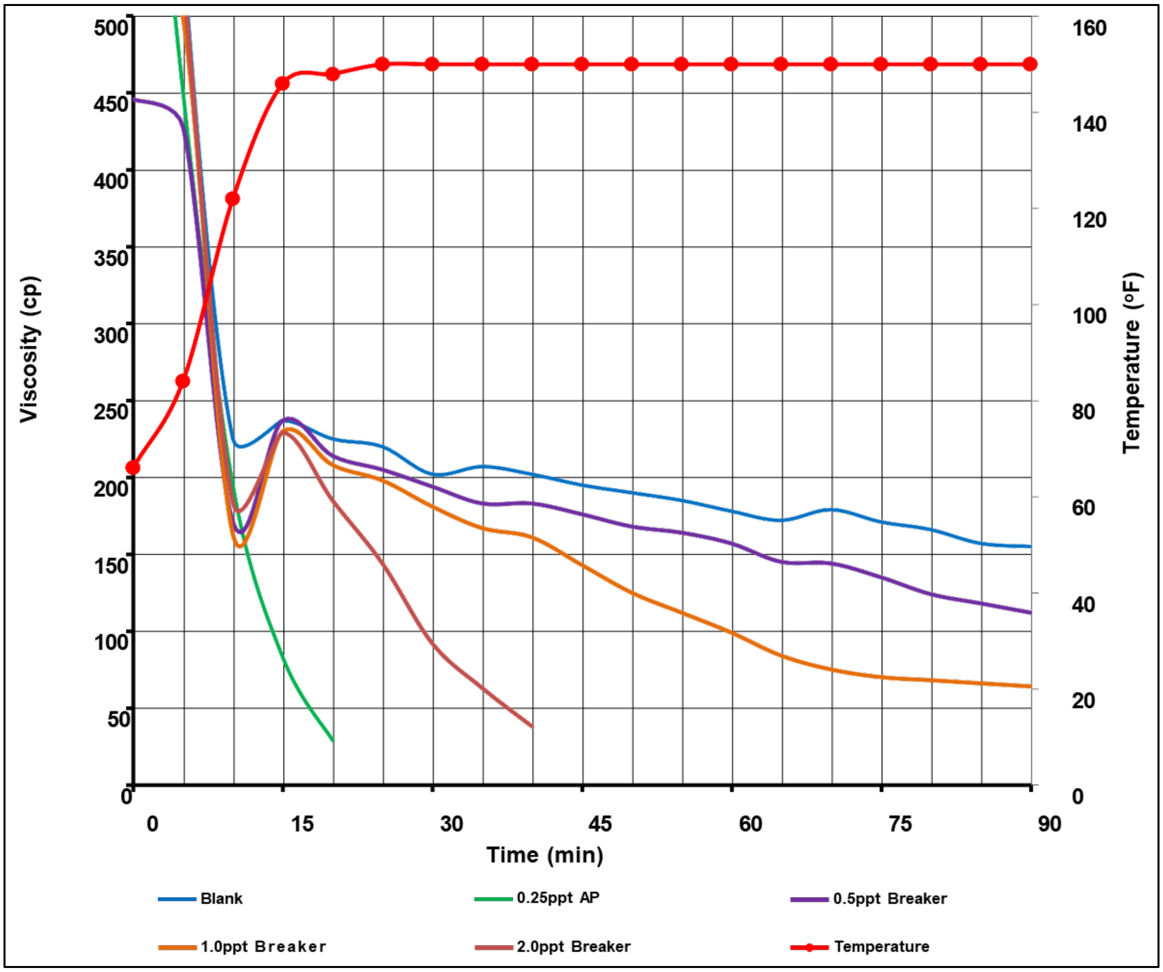

Figure 7: Gel Degradation

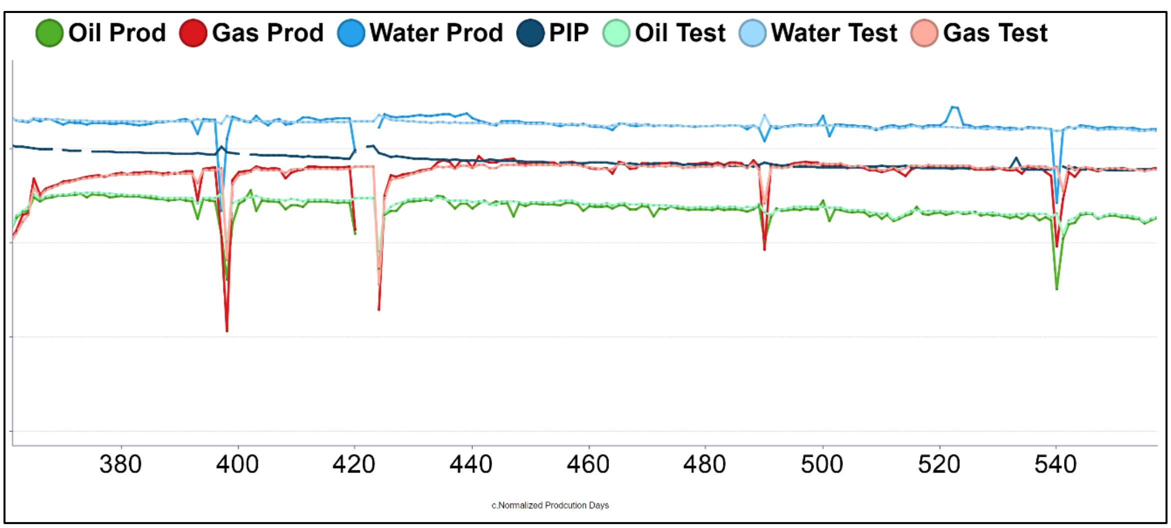

Figure 8: Well A production and intake pressure plot vs normalized days for 200 days post return to production