

CHLORINE DIOXIDE (ClO₂) FRACLESS RE-STIMULATION IN LEGACY HYDRAULIC FRACTURED WELLS. AN ALTERNATIVE TO REFRAC OPERATIONS

Panos Dalamarinis

DG Petro Oil and Gas

ABSTRACT

More than 200,000 horizontal multifractured wells are currently active across multiple unconventional basins in continental United States. The first completion designs relied on completion practices that had been utilized in conventional reservoirs, and the early wells completed with low proppant/fluid intensity and in many cases cluster/fracture spacing greater than 100 ft. Chlorine Dioxide (ClO₂) was field trialed as a Restimulation chemistry in a well D&C in 2015 as an alternative to traditional Refrac operations.

Well R is a well D&C in 2015 in Culberson County, Texas with a lateral of 7,058 ft. At the first 4,300 ft, the well was completed with a perforation design of 6 clusters 8 ft apart, followed by 183 ft of spacing to the next group of clusters. For the remaining part of the lateral, a perforation design with clusters ~38 ft apart was used. The pumping schedule was a hybrid design of slickwater/X-link gel. A Chlorine Dioxide (ClO₂) Re-stimulation treatment was engineered and pumped in 01/2025, and the well, which had been shut-in since 11/2017, was returned to productio

Initial production rates IP30 of ~ 230 bopd and 1,700 Mscfd were recorded (01/2025), approximately 65% of the initial production rates when the well was first put in production in 10/2015. The well demonstrates better cumulative oil/gas production and EUR when compared to the well's initial production after 9 months of flow back. Reservoir/Production/RTA modeling results of a theoretical Refrac option (CAPEX, production volumes, and NPV) were compared to the actual costs and production results, with the ClO₂ re-stimulation treatment providing better economics and NPV without posing the mechanical/engineering risk of a traditional restimulation method (bull head Refrac or liner re-frac). Realized production data and performance of Well R further validated the theory presented by Dalamarinis et al . (2023, 2025) that production degradation is not exclusively related to depletion, but mainly to skin damage mechanisms developed inside the fracture system. It also expanded the range/criteria of wells at which Chlorine Dioxide (ClO₂) treatments can be applied (fracture system spacing ~ 180 ft) with similar success to the cases previously presented to the industry.

Re-stimulation with Chlorine Dioxide (ClO₂) proved to be an effective method to restore production and reservoir conductivity in a well that traditionally would be considered a Refrac candidate. Without the need to invest millions of dollars and operational risk in bull head or liner refrac operations, operators can utilize Chlorine Dioxide (ClO₂) as an alternative restimulation strategy that offers better economics and efficiencies.

Introduction

The EIA estimates around 200,000 active unconventional horizontal wells in the continental US. Almost 70% of these wells currently produce under 100 BOE/D and over 50% are below 50 BOE/D (EIA, 2024).

An alternative to improve EUR is to conduct a second frac operation or chemically Enhanced Oil Recovery (EOR). Refracs have been a consideration since we began fracturing wells in the 1950's and are commonplace in vertical wells. In some estimates, almost 1/3 of frac jobs in vertical wells are Refracs (Wiseman, 2017). In a vertical well, a properly designed Refrac can easily extend the original fracture geometry to contact new reservoir and can effectively bypass any near wellbore damage.

Horizontal wells with hundreds of perforations require more complex and costly Refrac operations. Common techniques include:

- i. A bullhead frac with the use of diverting agents in an attempt to stimulate different areas of the well (also referred to as Pump and Pray Refracs),
- ii. Straddle Fracs, which employ tubing-conveyed packers to isolate individual zones for the stimulation through the existing perforated production liner,
- iii. Running expandable liners and completed via plug and perf operations, or
- iv. Running a new smaller liner cemented in place and completed via plug and perf operations.

Pump and Pray Refracs, as the name implies, provide very little control of where fluids and proppant are directed and often result in over-stimulation of the heel and under-stimulation of the rest of the perforated interval. This increases the risk of frac hits, and results are unpredictable at best. In Straddle Fracs, the risk of sticking BHAs downhole can be a huge deterrent, and in addition, reduced tubing sizes may significantly restrict frac design parameters.

Only Refracs where new liners are set and reperforated can guarantee targeted horizontal coverage and allow for modern frac designs. The cost of Refrac'ing a horizontal well can be elevated; for a typical 1.5-mile lateral, total costs can be north of 4.5 million dollars. Some best practices include:

- i. A wellbore clean-out procedure to clear debris and prepare the existing liner for mechanical isolation or cementing of a new smaller liner

- ii. A well-designed cementing program for the Refrac liner to ensure the required mechanical integrity and enable efficient frac design
- iii. Frac designs that can ensure required frac propagation with pump rates limited by the reduced wellbore dimensions.
- iv. A zonal isolation strategy that will target under-stimulated zones effectively, usually a reduced-bore plug and perforation systems.

Due to these elevated costs, candidate selection is critical, and the technique is often only applicable to wells that were completed with early-generation or Legacy frac designs. Legacy horizontal fracturing designs typically involved fewer and smaller stages, longer stage and perforation spacing, and lower pump rates compared to modern designs, aiming for a simpler fracture distribution but often leaving significant amounts of pay zone untouched and resulting in low EURs.

Furthermore, Cross-linked or Hybrid frac programs introduced vast amounts of guar gel into the reservoir. If the breaker system fails to completely break the guar gel, it may coagulate under high temperatures into a thick gelatinous substance, which easily blocks pores and proppant packs, resulting in significant skin damage. When remediating these wells, it is common to see large amounts of unbroken gel in the flowback, even years after the original completion (Fig 1). ClO_2 is known for its efficacy in dissolving polymers (Figures 1 & 2).



Figure 1: Guar gel recovered from wellbore.



Figure 2: Solubilization of dehydrated guar gum residue using acidified Chlorine Dioxide (ClO₂).

Re-lined refracs designed to improve recovery factors are common in plays like the Bakken, Barnett, and Eagle Ford, where Legacy frac designs during early development resulted in under-stimulated horizontal laterals. While the primary motivation to conduct a refrac is sometimes to create a stress barrier and protect the parent well when stimulating a nearby well, refrac strategies to improve EUR of horizontal wells that were completed with modern frac designs have not been as widely adopted due to economic feasibility limitations.

Enverus started tracking refracs in January of 2023 and their data shows that over the last 2 years there have been an estimated 53 refracs in the Permian basin as compared to 15,392 total completions. Less than 1% incidence.

Table 1: Total Number of Refracs and Total Completions in US (Enverus).

BASIN	TOTAL COMPLETIONS	REFRACS	%
Bakken	2306	165	7.2%
Barnett	267	22	8.2%
Eagle Ford	3198	156	4.9%
Permian	15392	53	0.3%
Other	16920	68	0.4%
Total	38083	464	1.2%

Data collected between 1/1/2023 to present
Courtesy of Enverus

In cases where a well is underperforming due to skin damage, remediation techniques may be more economically feasible and, if properly designed, can also offer an EOR component. A new concept of Enhanced Oil Recovery (EOR), Fracture EOR (F-EOR), has been developed in the Permian basin by Dalamarinis (2023 & 2025) with the use of acidified Chlorine Dioxide (ClO₂) to provide large production uplifts and Oil and Gas

EUR improvements. Trials conducted over the last three years with more than 60 jobs throughout multiple counties in West Texas have yielded recovery factor increases as high as 100%, averaging 50% improvement. (Dalamarinis et al., 2023, 2025). These ClO₂-EOR operations offer a novel low-cost alternative to refracs and “Huff and Puff” operations.

This paper will offer a detailed cost-reward comparison between refrac and ClO₂-FEOR Restimulations for a Delaware Basin horizontal well that would be considered a refrac candidate based on industry norms (Barba, 2023, Fowler et al., 2023).

CANDIDATE WELL HISTORY AND EVALUATION

A different fracless re-stimulation methodology was field tested and will be presented in this work and involves treatments with Chlorine Dioxide (ClO₂). Dalamarinis et al. (2023 & 2025) utilized Chlorine Dioxide (ClO₂) treatments for Enhanced Oil Recovery (EOR) and restimulation in horizontal multifracture Permian Basin wells, completed in different formations and reservoirs, achieving significant uplift in production and EUR. Most of the wells treated with Chlorine Dioxide (ClO₂) were wells at which the original completions were performed between 2017-2022. Completion fluid was slickwater, and the cluster spacing in those wells ranged from 18 to 40 feet.

Production, downhole pressure data, and reservoir/production analysis before and after those treatments proved that production and pressure decline are not exclusively related to depletion, but to skin damage mechanisms developed inside the fracture system due to scale, paraffin, asphaltene and biomass (Dalamarinis et al., 2023 & 2025).

Even though ClO₂ treatments proved successful in wells with the completions designs mentioned above, the question standing was, if they could be efficient in restimulation of legacy wells with fracture/cluster systems with spacing bigger than 40 feet, and hybrid completion designs (slickwater, linear gel, X-link gel), designs that were first used in multiple unconventional basins across the continental United States. Wells with completion designs as such are considered re-frac candidates based on the industry norms, and operators usually recomplete those wells with either bullhead sand re-fracs or plug and perf with the installation of a liner inside the existing production casing. This type of operation is used because of the general assumption that the legacy fracture systems have already depleted the rock in which they were placed, and new unstimulated rock needs to be connected to the existing wellbore for production and EUR uplift.

In 2025, a Wolfcamp A well (“Well R”), Drilled & Completed (D&C) in 2015 in Culberson County, Texas, was selected to test if Chlorine Dioxide (ClO₂) can be a more efficient and effective restimulation method, without the operational/engineering risk and cost of typical re-frac operations.

Well R has a horizontal net lateral of 7,058 ft. On the first 4,300 ft. the well was stimulated with a perforation design of 6 clusters 8 ft apart, followed by 183 ft of spacing to the next

group of clusters (20 stages – Zone A). For the remaining part of the lateral, a perforation design with clusters ~38 ft apart was used (13 stages – Zone B) Figure 3.

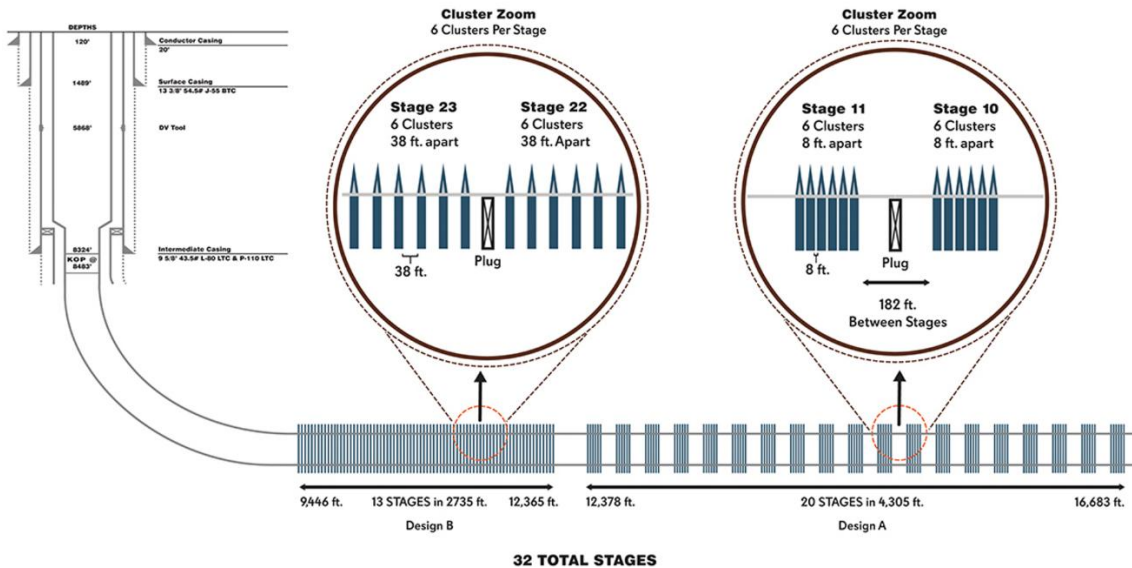


Figure 3: Representation of the completion design/fracture system of Well R.

The pumping schedule was a hybrid design of slickwater/X-link gel with 97% of the proppant being 40/70 & 30/50 mesh (Table 2). At each stage for both cluster configurations (Design A & B), ~ 440,000 lbs. of proppant and 7,800 bbls. of fluid was pumped.

The original pumping schedule consisted of:

1. ~440,000 lbs. of proppant
 - 3% 100 mesh - 29% 40/70 mesh - 68% of 30/50 mesh
2. ~7,800 bbls of total fluid
 - 30% Slickwater - 33% 25# Frac Gel - 36% Hybor 25# X-link
3. 42% Slickwater Pad with two sweeps of 100 mesh at 0.25 and 0.5 ppg

Table 2: Initial Pumping Schedule of Well R (All Stages).

	15% HCl Acid	73	bbl	Oklahoma #1 100 Mesh	15,011		
	Slickwater	2,341	bbl	Ottawa Sand 40/70	128,258		
	25 # Water Frac G	2,489	bbl	Ottawa Sand 30/50	303,551		
	Hybor 25 #	2,786	bbl				
	TOTAL	7,689	bbl	TOTAL	446,820	Final frac gradient	
Stage	Fluid Type	Clean gal	Slurry bbl	Rate bpm	Conc, ppg	Stage lb	Proppant
					Start End		
1	Pumpdown fresh water	8,825	210	15	0.00 0.00	0	
2	Slickwater	11,704	279	20	0.00 0.00	0	
3	15% HCl Acid	3,080	73	80	0.00 0.00	0	
4	Slickwater	13,102	312	80	0.00 0.00	0	
5	Slickwater	15,186	366	80	0.25 0.25	3,797	Oklahoma #1 100 Mesh
6	Slickwater	11,970	285	80	0.00 0.00	0	
7	Slickwater	22,529	549	80	0.50 0.50	11,265	Oklahoma #1 100 Mesh
8	Slickwater	12,030	286	80	0.00 0.00	0	
9	25 # Water Frac G	18,511	451	80	0.50 0.50	9,256	Ottawa Sand 40/70
10	25 # Water Frac G	18,030	444	80	0.75 0.75	13,523	Ottawa Sand 40/70
11	25 # Water Frac G	22,002	548	80	1.00 1.00	22,002	Ottawa Sand 40/70
12	25 # Water Frac G	21,987	559	80	1.50 1.50	32,981	Ottawa Sand 40/70
13	25 # Water Frac G	24,011	624	80	2.00 2.00	48,022	Ottawa Sand 40/70
14	Hybor 25 #	31,979	831	80	2.00 2.00	63,958	Ottawa Sand 30/50
15	Hybor 25 #	37,982	1,007	80	2.50 2.50	94,955	Ottawa Sand 30/50
16	Hybor 25 #	24,292	658	80	3.00 3.00	72,876	Ottawa Sand 30/50
17	Hybor 25 #	14,006	387	80	3.50 3.50	49,021	Ottawa Sand 30/50
18	Hybor 25 #	6,673	188	80	4.00 4.00	26,692	Ottawa Sand 30/50
19	Hybor 25 #	2,079	50	80	0.00 0.00	0	
20	Slickwater	11,784	281	80	0.00 0.00	0	

The well was brought to production with initial IP30 rates of ~ 350 bopd and 2,500 Mscfd. Water cut was ~ 85%. After the initial flowback (10/2015 to 04/2016), the well was put on production with the help of:

- a) Conventional Gas Lift (from 05/2016 – 06/2017)
- b) Jet Pump (from 07/2017 – 10/2017)

For the majority of 2017, well's hydrocarbon production declined to less than 20 boed, and water cut increased to >99%, making Well R uneconomic to operate (Figure 4). The operator who D&C the well decided to shut it in, and since October of 2017, the well was considered a Plug & Abandoned (P&A) candidate.

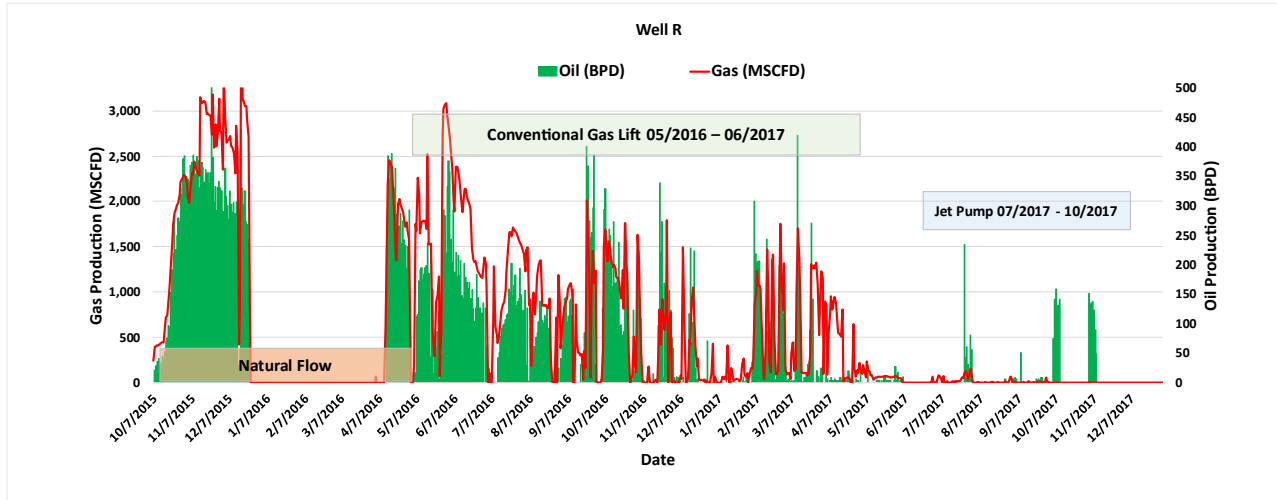


Figure 4: Production Profile and Type of Legacy Artificial Lift Systems of Well R.

Production versus Material Balance Time (MBT) analysis was performed (Economides et al., 2013), and the results are shown in Figure 5. A very brief period of Linear flow followed by Boundary Dominated Flow can be observed for the period between 2015-2017, an indication based on traditional reservoir analysis (Economides et al., 2013, Moridis et al.) that the stimulated rock (SRV) by the legacy completion has been depleted.

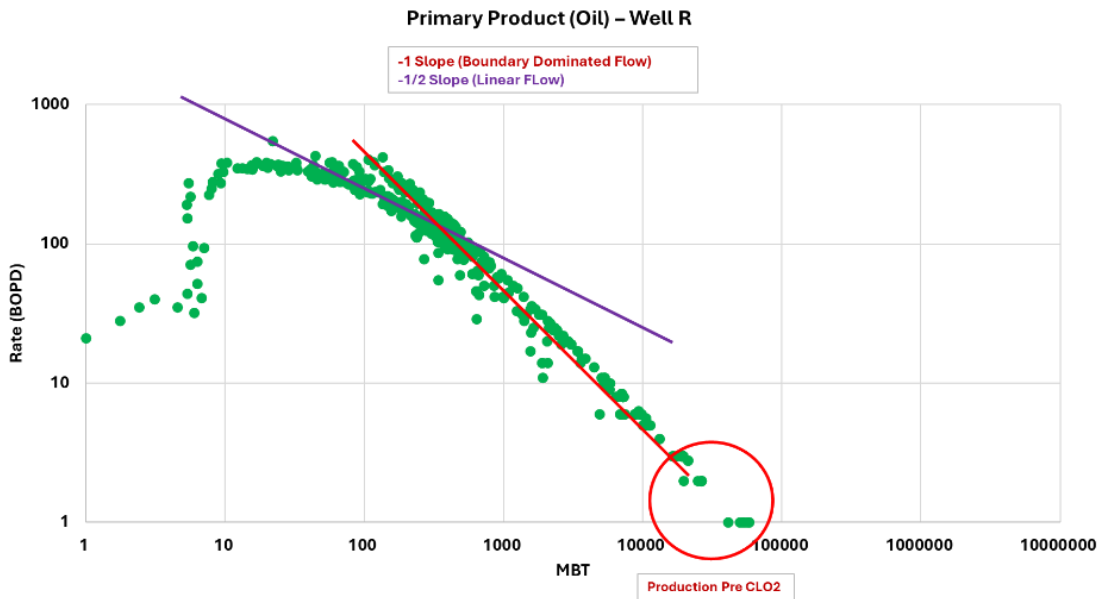


Figure 5: Production vs MBT for Well R (2015 - 2017).

When DG Petro Oil & Gas first acquired the asset in which Well R is located, they initially decided to leave the well shut-in. Due to the successful utilization of Chlorine Dioxide (ClO₂) treatments for EOR and Re-stimulation between the years of 2022 - 2024 in

different areas of the Permian Basin (Dalamarinis et al., 2023, 2025), an economic and engineering evaluation was conducted to determine the potential of Well R.

Two options were considered for re-stimulation: a) setting a liner and re-frac the unstimulated rock along the lateral in the zones where no fracture system was created, and b) re-stimulate Well R with a modified engineered Chlorine Dioxide (ClO₂) treatment. In the following sections of this work, we will present the economic (CAPEX, NPV) and engineering aspects of the work performed on Well R. The production of Well R after the Chlorine Dioxide (ClO₂) Re-stimulation treatment pumped will be compared to the well's initial production along the theoretical modeled production performance of a re-frac case based on a Production/Reservoir/RTA model that was built for this purpose.

ENGINEERING EVALUATION AND ECONOMIC ANALYSIS

Detailed operational procedures and AFEs were generated for the two recompletion options.

Re-frac The Well After the Installation of an Expandable Liner.

The workover/recompletion operations would consist of the following steps:

- a) Remove the Artificial Lift System (Jet Pump)
- b) Pressure test the casing
- c) Clean out the lateral to TD
- d) Run Wireline and identify tie-in points for the new perforations/stages
- e) Run and set a 3 ½ x 5-inch expandable liner in the existing 5 inch production casing
- f) Re-frac Well-R with two different completion designs (Table 6)
 - a. Plug and perforate the unstimulated zones in Zone A (Figure 6 – Design A)
 - i. ~170 feet stages
 - ii. 9 clusters per stage 17 feet apart
 - iii. Pump a treatment of 2,500 lbs. of proppant and 57 bbls of fluid per foot (Table 3)
 - b. Plug and perforate new clusters between the existing clusters at the legacy stages (stage 21-33) in Zone B (Figure 6 – Design B)
 - i. Legacy clusters ~38 feet apart – shoot new clusters in-between
 - ii. 5 clusters per stage ~19 feet apart from each legacy cluster
 - iii. Pump a treatment of 184,000 lbs. of proppant and 4,200 bbls of fluid per stage (Table 3)
- g) Install Single Point Gas Lift and bring the well to production

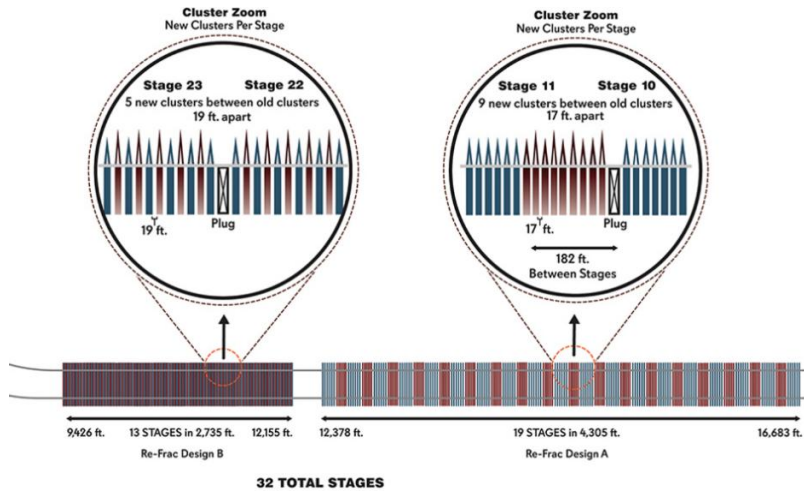


Figure 6: Proposed Refrac Perforation Scheme for Well R (Red Color: New Clusters/Fractures).

Table 3: Pump Schedules for Refrac Option in Well R (Left: Zone A, Right: Zone B).

TREATMENT SCHEDULE: STAGES 1 - 19									
STEP NUMBER	FLUID	STEP TYPE	CLEAN VOLUME, Gal.	RATE, (BPM)	PROP TYPE	CUM. PROPANT, Lbs.	PROP CONC., lbs/Gal.	Stage Time, Mins.	Cum. Time, Mins.
1	Slickwater	Pump Down	5,200	25	n/a	0	0.00	5.0	5.0
2	Slickwater	Breakdown	320	25	n/a	0	0.00	0.3	5.3
3	15% HCl	Acid	1,600	25	n/a	0	0.00	1.5	6.8
4	Slickwater	Pad	23,400	70	n/a	0	0.00	8.0	14.8
5	Slickwater	Slurry	38,100	70	100 Mesh WTX	19,050	0.50	13.3	28.1
6	Slickwater	Slurry	43,670	70	100 Mesh WTX	62,720	1.00	15.5	43.6
7	Slickwater	Sweep	16,000	70	n/a	62,720	0.00	5.4	49.0
8	Slickwater	Slurry	34,150	70	100 Mesh WTX	113,945	1.50	12.4	61.4
9	Slickwater	Slurry	30,200	70	100 Mesh WTX	166,796	1.75	11.1	72.5
10	Slickwater	Slurry	27,800	70	40/70 Mesh WTX Premium	201,545	1.25	10.0	82.5
11	Slickwater	Slurry	31,760	70	40/70 Mesh WTX Premium	249,185	1.50	11.5	94.0
12	Slickwater	Slurry	34,600	70	40/70 Mesh WTX Premium	309,735	1.75	12.7	106.7
13	Slickwater	Slurry	19,100	70	40/70 Mesh WTX Premium	347,935	2.00	7.1	113.8
14	Slickwater	Flush	21,000	70	n/a	347,935	0.00	7.1	120.9

TREATMENT SCHEDULE: STAGES 20 - 32									
STEP NUMBER	FLUID	STEP TYPE	CLEAN VOLUME, Gal.	RATE, (BPM)	PROP TYPE	CUM. PROPANT, Lbs.	PROP CONC., lbs/Gal.	Stage Time, Mins.	Cum. Time, Mins.
1	Slickwater	Pump Down	6,500	25	n/a	0	0.00	5.0	5.0
2	Slickwater	Breakdown	400	25	n/a	0	0.00	0.3	5.3
3	15% HCl	Acid	1,175	25	n/a	0	0.00	1.5	6.8
4	Slickwater	Pad	12,220	45	n/a	0	0.00	8.0	14.8
5	Slickwater	Slurry	12,000	45	100 Mesh WTX	6,000	0.50	13.3	28.1
6	Slickwater	Slurry	19,000	45	100 Mesh WTX	25,000	1.00	15.5	43.6
7	Slickwater	Sweep	12,000	45	n/a	25,000	0.00	5.4	49.0
8	Slickwater	Slurry	17,000	45	100 Mesh WTX	50,500	1.50	12.4	61.4
9	Slickwater	Slurry	16,000	45	100 Mesh WTX	78,500	1.75	11.1	72.5
10	Slickwater	Slurry	14,000	45	40/70 Mesh WTX Premium	96,000	1.25	10.0	82.5
11	Slickwater	Slurry	15,040	45	40/70 Mesh WTX Premium	118,560	1.50	11.5	94.0
12	Slickwater	Slurry	17,500	45	40/70 Mesh WTX Premium	149,185	1.75	12.7	106.7
13	Slickwater	Slurry	15,000	45	40/70 Mesh WTX Premium	179,185	2.00	7.1	113.8
14	Slickwater	Flush	18,000	45	n/a	179,185	0.00	7.1	120.9

The total cost based on the actual AFE built to re-frac and bring Well R to production is presented in Table 4.

Table 4: Cost of Liner Refrac Operations for Well R.

Well R Recompletion Cost (\$)	
Remove Lift System, Clean-Out Lateral, Set Liner	\$ 1,303,465
Re-Completion	\$ 2,112,535
Install Single Point Gas Lift	\$ 200,000
Surface Facilities	\$ 190,000
Total Cost	\$ 3,806,000

Re-Stimulate Well R with Chlorine Dioxide (ClO₂)

To treat the well with Chlorine Dioxide (ClO₂) after engineering the design to address the legacy completion design along the lateral of Well R, the workover/recompletion operations were adjusted as follows:

- a) Remove the Artificial Lift System (Jet Pump)
- b) Clean out the lateral to TD
- c) Pump Chlorine Dioxide (ClO₂) – Table 6
- d) Install Single Point Gas Lift and bring the well to production

The total cost based on the AFE built to re-stimulate with Chlorine Dioxide (ClO₂) and bring Well R to production is presented in Table 5.

Table 5: Cost of Recompletion Operations for Well R.

Well R Chlorine Dioxide (ClO ₂) Re-Stim Cost (\$)	
Remove Lift System, Clean-Out Lateral	\$ 270,000
Chlorine Dioxide (ClO ₂)	\$ 130,000
Install Single Point Gas Lift	\$ 200,000
Surface Facilities	\$ 190,000
Total Cost	\$ 790,000

Considering the significant cost difference between the two re-stimulation options, the operational risk of setting a liner and re-frac Well R, and the success DG Petro Oil & Gas has with Chlorine Dioxide (ClO₂) treatments, it was decided to Restimulate the well with Chlorine Dioxide (ClO₂).

Table 6: Original Completion and Proposed Restimulation Options for Well R.

	Design/Zone A	Design/Zone B	
Original Stimulation	Measured Depth (ft)	12,378-16,683	9,426-12,155
	Lateral Length (ft)	4,305	2,735
	Stages	20	13
	Stage Length (ft)	~215	~210
	Cluster Spacing (ft)	8	38
	Cluster per Stage	6	6
	Perforations per Stage	30	30
	Proppant per stage (lbs)	445,960	445,960
	Fluid System	Hybrid (XL/GEL/SLK)	Hybrid (XL/GEL/SLK)
	Fluid Load per Stage (bbls)	9,662	9,662
	Refrac Stimulation	Measured Depth (ft)	12,378-16,683
Lateral Length (ft)		4,305	2,735
Stages		19	13
Stage Length (ft)		170	~210
Cluster Spacing (ft)		17	19
Cluster per Stage		9	5
Perforations per Stage		36	30
Proppant per stage (lbs)		326,900	184,006
Fluid System		Slickwater	Slickwater
Fluid Load per Stage (bbls)		7,783	4,187
ClO₂ Restim	Treatment Volume (bbls)	~2,900	

It would also be an excellent case and proof of concept that wells that would otherwise be considered re-completion/frac candidates by industry standards norms (Barba, 2023, Fowler et al., 2023) due to fracture system/cluster spacing, can achieve significant production and EUR uplift for a fraction of the cost when compared to re-frac operations. Also, it would further validate the theory that production decline, even in wells with fracture systems >100 feet apart, is not exclusively related to reservoir depletion, but to damaged fracture conductivity/connectivity due to skin damage and plugging mechanisms inside the fracture system (Dalamarinis et al., 2025).

Production, Reservoir and RTA Modeling for Well R

Of equal importance to CAPEX, operational risk and production, is the understanding of the theoretical performance of a refracture operation at Well R, its overall economics, and how those compare to the actual realized production after the Chlorine Dioxide (ClO₂) treatment.

To evaluate this aspect of performance/economics, a Production, Reservoir, and RTA model/workflow for Well R was built. The core of this work was a) the depletion that the existing fracture system created, and b) the depletion and production performance of the fractures created by the recommended re-completion design that was evaluated and outlined above (set liner and re-stimulate). The workflow that was followed is outlined below:

1. Identify and evaluate open hole logs and core samples from pilot wells that had been drilled in the area.
2. Build a stress profile of Wolfcamp and run for Well R a fracture propagation model (multi-layer Pseudo-3D) to estimate the Stimulated Reservoir Volume (SRV) taking in consideration (Economides et al, 2002, 2008):
 - a. Stress/geo-mechanical profile (Young Modulus, Poisson Ratio, Horizontal, Vertical and Minimum In-situ Stress, Fracture Toughness)
 - b. Completion schedule (fluid/proppant volume, type of fracturing fluid/proppant, pumping rate, perforation scheme)
3. Estimate of total SRV and drainage volume based on frac model results along lateral length in Area/Zone A & B (Figure 3).
4. Develop a petrophysical model and estimate of oil/gas in place, porosity, permeability, and water Saturation (Sw). The work that was used relied on correlating area core data to log readings to calculate OIP, GIP, TOC, Carbonate/Clay/Clay/Silica content, based on the methodology presented by Asquith & Downey.
5. Build and use a finite fracture conductivity model to estimate depletion/production on per cluster level for the legacy completion design. The Production Models used to get the optimum match between theoretical and actual production data are the following:
 - a. Late Linear Flow
 - b. Exponential Decline
 - c. Harmonic Decline
 - d. Hyperbolic Decline

6. Use in step 5 the results from the fracture and petrophysical model properties and run iterations to achieve the best correlation/match between the actual production data and model predictions for the legacy fracture system in Well R (Primary Product – Oil).
7. Use the calibrated model from the above process and estimate the production performance (Primary Product – Oil) of the fracture systems created by the new recompletion program proposed in the “Engineering Evaluation and Economic Analysis” section
8. Calculate the production profile of Well R after Restimulation.

The method that provided the best match between actual and modeled production data for Well R was the Late Linear Flow Model. Results and correlations of all RTA/Production methods that were used as described in Step 5 of the procedure outlined above are presented in Figures 7 & 8. Late Linear Flow Model was used to estimate the production of the Refrac case and will be used in the following sections for production comparisons with the well’s actual production and economic analysis and Net Present Value (NPV) calculations.

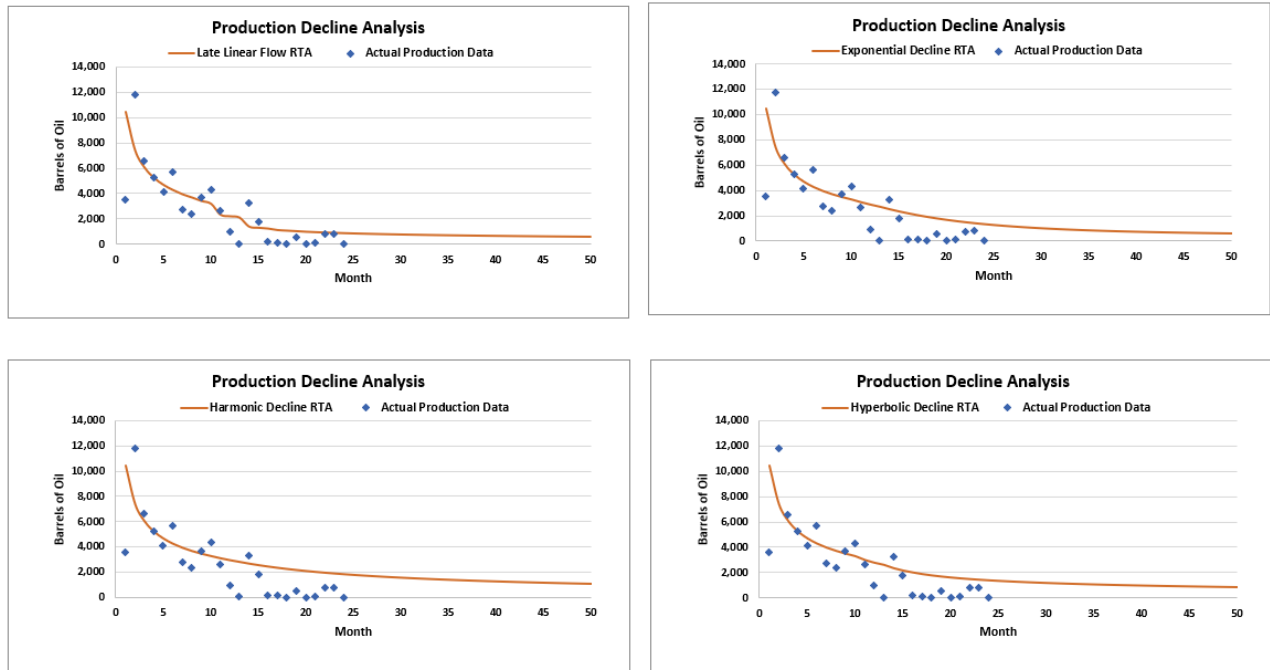


Figure 7: Correlation Between Actual Production Profile and Type of Production Decline Method for Well R.

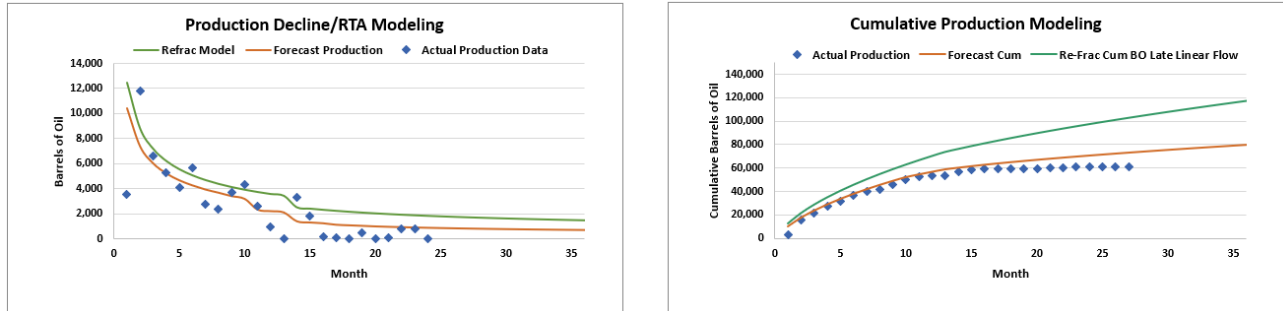


Figure 8: Correlations Between Actual Legacy and Modeled Production (Late Linear Flow Model) for Well R and Expected Re-frac Production Profile.

PRODUCTION RESULTS OF CHLORINE DIOXIDE (ClO₂) FRAC-LESS

RESTIMULATION FOR WELL R

Workover operations commenced on January of 2025. The artificial lift system (jet pump) and production tubing were removed, and the lateral was cleaned out to the last perforation at ~ 16,685 feet. Except for a scale bridge that was encountered at the heel of the well, before the first perforations, no additional hard tags due to scale along the lateral were recorded.

An engineered Chlorine Dioxide (ClO₂) treatment (Dalamarinis et al, 2025) was pumped at Well R on 02/2025. Bio-balls were used for diversion, and a total of six stages of Acid/Chlorine Dioxide (ClO₂) were pumped with a total treatment volume of ~2,900 bbls. Tailored Nano-surfactants added to the fluids to help with long term production decline (Dalamarinis et al., 2023). The well which was shut-in since November of 2017 was returned to production with the help of Single Point Gas Lift.

Single Point Gas Lift (SPGL) was installed with open-ended tubing landing at ~ 80 degrees in the curve (~9,400 ft MD). The primary reason this Artificial Lyft System was selected was because wells in the area demonstrate high scale tendencies and influx of reservoir solids, resulting to operational issues, downtime and premature failures when different artificial lift systems are used (Dalamarinis et al., 2024, McNeilly et al., 2024). Previous experience and work from DG Petro Oil & Gas, as well as offset operators (McNeilly et al., 2024), showcased that Single Point Gas Lift (SPGL) is “immune” to scale and reservoir solid issues, and can operate with minimal downtime for extended periods of times (> 4 years without the need of workover/replacement for wells DG Petro Oil & Gas Operates in the area at the time authoring this paper).

The well was brought online, and flowback operations commenced. During the first weeks of flow back operations, fluid samples were collected (Figures 9 and 10). An interesting observation during the dewatering phase was that alongside with oil, reservoir water and an interphase of iron, a higher viscosity fluid was collected from the well/separator (Figure 9). In the fluid samples, the presence of gel was recorded. Considering that the only gel

pumped at this well was Liner Gel and Borate X-Link (Hybor 25#) during the initial completion, it is very likely that Chlorine Dioxide (ClO_2) broke down this gel and managed to successfully flow it back after 10 years, hence improving connectivity with reservoir and activating part of the fracture system that was probably blocked off/isolated due to the frac gel.

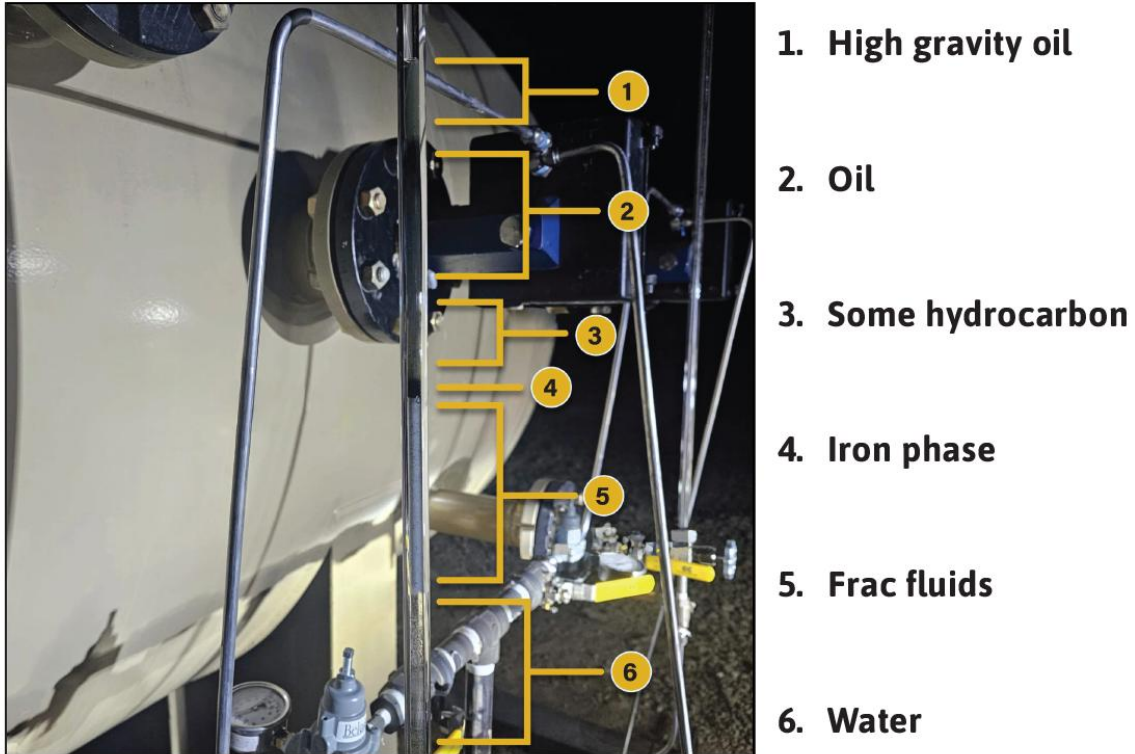


Figure 9: Flowback Fluids at Well R's Separator after Chlorine Dioxide (ClO_2) Treatment.

Realized IP30 production rates of Well R were ~ 230 bopd and 1,700 Mscfd, approximately 65% of the initial IP rates when compared to the well's production in 10/2015 after the original completion (Figure 11).



Figure 10: Flowback Fluid of Well R After 2 Days (Left) and 14 Days (Right) post ClO₂ Treatment.

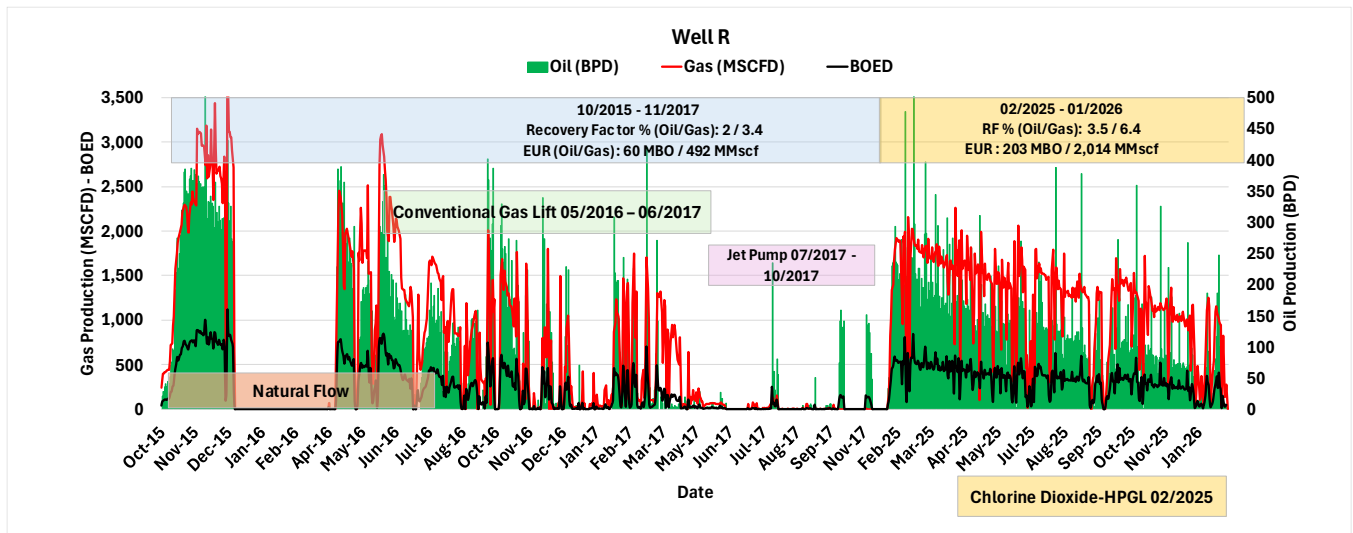


Figure 11: Production of Well R After pre and post ClO₂ Treatment.

One year after the ClO₂ treatment, Well R demonstrates better cumulative oil/gas production and EUR when compared to the well's initial 12-month production (Figures 11 & 12). In the first year after the original completion, Well R produced 44,968 bbls of oil and 387,804 Mscf of gas. Before the well was deemed uneconomic and shut in October of 2017, it produced a total of 60,458 bbls of oil and 491,939 Mscf of gas.

One year post the ClO₂ job, the well has produced 46,658 bbls of oil and 440,908 Mscf of gas. This is ~78% of the well's total production in the period 10/2025 – 10/2017. Based on the production behavior and decline Well R demonstrates (01/2026 - Figure 11), it is

estimated that the production post the ClO_2 treatment will exceed the production of Well R between 10/2015 - 10/2017. Figure 13 presents Well R's production response post ClO_2 from public sources (Enverus). According to the Production vs MBT data in Figure 14, Linear Flow post the ClO_2 Restimulation is observed, an indication of conductivity/connection restoration between the well, fracture system, reservoir, and production from un-depleted reservoir (Dalamarinis, 2025). A clear indication that the reservoir of Well R is not depleted.



Figure 12: One Year Cumulative Production of Well R Post Original Completion (2015) & ClO_2 Treatment (2025).

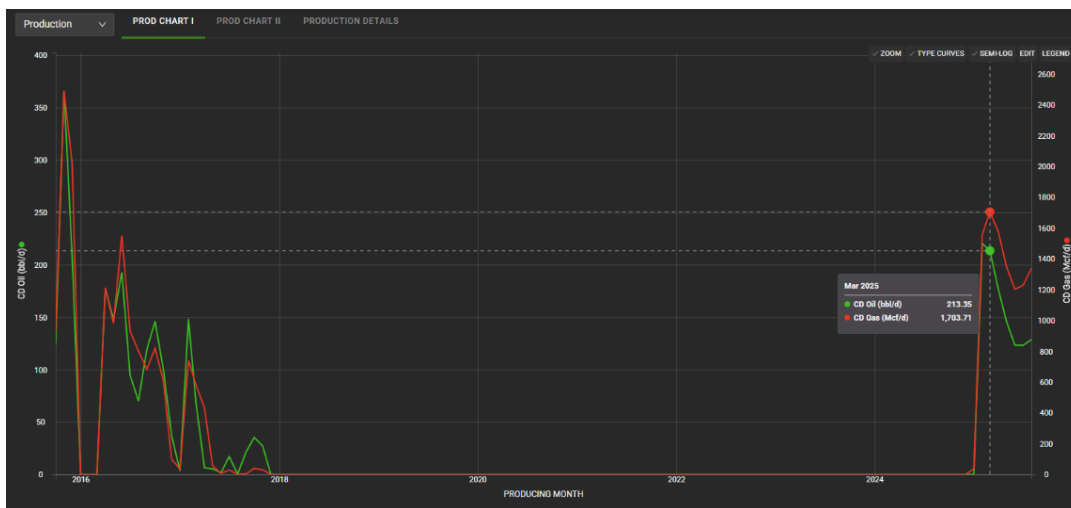


Figure 13: Historic Production of Well R and Production Response Post ClO_2 Treatment (Enverus – Public Data).

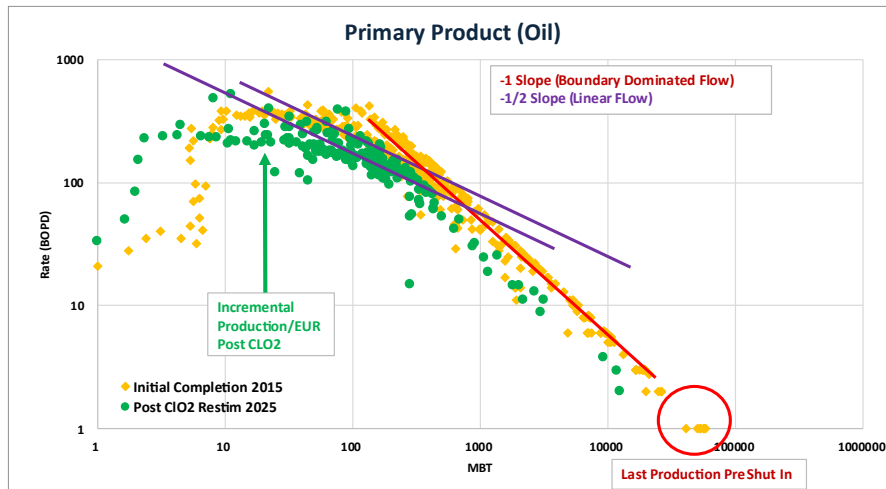


Figure 14: Production vs MBT for Well R (Initial Completion & Post ClO₂ Restimulation).

NET PRESENT VALUE (NPV) OF CHLORINE DIOXIDE (ClO₂) TREATMENT VS LINER PROPPANT RE-STIMULATION

Of equal importance to production is the economic performance of a workover or a recompletion operation. To demonstrate this aspect of the effectiveness of Chlorine Dioxide (ClO₂) Re-Stimulation, an economic analysis performed for both ClO₂ and Refrac options.

For the calculation of the Net Present Value (NPV) of these two options, the following data was used:

1. Production
 - a. For the ClO₂ Restimulation the realized production data of Well R was used. The first four months of actual production data were utilized, and performing Decline Curve Analysis on those, a 3-year production projection was generated (Figure 15).
 - b. For the Refrac case, the Production, Reservoir and RTA model/workflow for Well R that was built and presented in the previous section was used (Late Linear Flow Model). The model's 5-year production forecast was utilized in the economic calculations for this case (Figure 15).
2. CAPEX
 - a. The actual cost of the ClO₂ restimulation job was used
 - b. For the Refrac option, the total cost from the generated AFE was used
3. OPEX – For both cases, the actual realized costs by DG Petro Oil & Gas were used and include the following:
 - a. Cost for oil and gas handling (\$ per bbl. and Mscf)
 - b. Rental costs of surface equipment/facilities (compressors, fuel, etc.)
 - c. Water disposal fees at SWDs for the produced water

- d. Field personnel monthly salaries
 - e. Downhole and surface facilities chemical treatment costs
4. Commodity Prices (Oil & Gas) – For both cases, the realized/hedged sale prices of DG Petro Oil & Gas were used.

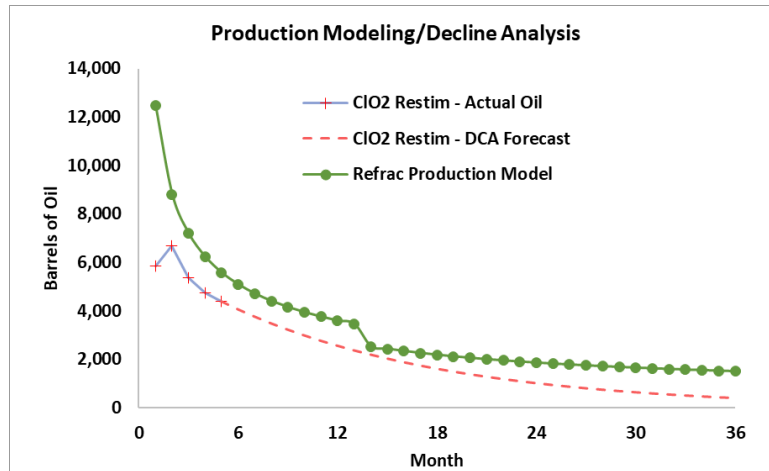


Figure 15: Actual/DCA CIO₂ and Refrac Reservoir Model Production for NPV calculations of Well R.

In Table 7, the production and economic performance of these two cases are presented. Chlorine Dioxide (ClO₂) Re-Stim job managed to pay off in approximately 65 days (based on actual realized production/sales). Refrac is estimated to have required ~1 year of production to reach payout.

Despite the higher expected production from a Refrac operation, the lower cost of Chlorine Dioxide (ClO₂) Re-Stimulation demonstrates better Net Present Value (NPV). 5-year NPV(10) of the ClO₂ Restimulation is ~ \$2.1MM versus \$1MM for the Refrac option.

Table 7: Economic Performance of The Two Restimulation Options for Well R.

Economics - Performance		
	Re-Frac	Chlorine Dioxide (ClO ₂) Re-Stim
Cost	\$3,806,000	\$791,000
Time to Pay Off	~ 360 days ¹	~ 65 days ²
5-Years Oil Production (BO)	134,183 ¹	86,421 ¹
5-Years Gas Production (Mscf)	855,422 ¹	705,789 ¹
5-Years NPV10	\$1,003,902 ¹	\$2,062,083 ¹
ROI	1.45 ¹	3.95 ¹

¹ Based on Reservoir Production/DCA Modeling, ² Based on Actual Production/Economic Data

CONCLUSIONS

The scope of this work is to evaluate if the Chlorine Dioxide (ClO₂) EOR/Restimulation methodology presented by Dalamarinis et al. (2023 & 2025) can be used to restore production and hydrocarbon recovery in wells which by industry standards would be considered refrac candidates. The results and conclusions of this work are presented below:

- Well R which was shut in since 2017 was returned to production after Chlorine Dioxide ClO₂ Restimulation.
- Realized IP30 production rates were ~ 230 bopd and 1,700 Mscfd, approximately 65% of the initial IP rates when compared to the well's production in 10/2015 after the original completion.
- Flowback samples indicated the presence of gel in the produced fluids, suggesting that ClO₂ effectively broke down and removed the frac gel from the existing fracture system, which had been pumped during the 2015 original completion.
- This treatment resulted in better cumulative oil and gas production over the first year compared to the well's initial first year production.
- The economic analysis showed that ClO₂ restimulation offered a Net Present Value (NPV10) of approximately \$2.1 million, which is significantly higher than the \$1 million NPV10 for traditional liner refrac operation.
- Additionally, the ClO₂ treatment had a payback period of 65 days, compared to ~1 year for the refrac option based on production/economic modeling.
- The production results further validated the theory that production decline in unconventional reservoirs is not solely related to reservoir pressure depletion but also to skin damage mechanisms within the fracture system.
- This work also expanded the selection criteria of wells that can benefit from Chlorine Dioxide (ClO₂) EOR and Restimulation treatments. It proved that even wells with fracture systems spaced more than 150 feet apart can achieve significant production and economic uplift without the high CAPEX and operational risks associated with traditional refrac operations (casing and cement integrity, offset well frac hit and production loss).
- Due to low volumes (<4,000 bbls) and pumping time (< 2 hours) of the Chlorine Dioxide (ClO₂) treatments, when compared to a typical "bull head" or liner refrac operation, offset wells do not need to be shut in and there is zero risk for a frac hit and production downtime.
- This work further proved that traditional methods of flow regime identification, reservoir evaluation, and reserve estimation in unconventional reservoirs need to be re-evaluated and revised to address the skin damage mechanisms developed in the proppant pack of the fracture system during the production phase of a well.

- Engineered Chlorine Dioxide (ClO₂) treatments can be used as an alternative to refrac operations as this work demonstrated, offering better economics, similar performance and zero operational risk.

ACKNOWLEDGMENTS

The authors would like to thank DG Petro Oil & Gas for permission to publish this work.

REFERENCES

1. Dalamarinis P., Smith B., Fusselman S.: "Acid Restimulation in Legacy Wolfcamp Wells Utilizing Chlorine Dioxide (ClO₂). An Operator Case Study of Reservoir Conductivity and Near Wellbore Fracture System Reactivation," URTeC: 3818857 presented at Unconventional Resources Technology Conference, Denver, Colorado, USA, 13-15 June 2023.
2. Dalamarinis P., Fusselman S.: "A "New Concept" Of Enhanced Oil Recovery (EOR) In Permian Basin. Chlorine Dioxide (ClO₂) As Re-stimulation Agent In Unconventional, Multi-fractured Horizontal Wells," SPE-223521-MS presented at 2025 SPE Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, Texas, USA, 4-6 February 2025.
3. [U.S. Energy Information Administration \(EIA\): The Distribution of U.S. Oil and Natural Gas Wells by Production Rate with data through 2023, December 2024.](#)
4. Wiseman P.: "Refracturing gives producers another crack at declining wells. Improved frac procedures and the opportunity for strong cost-benefit balances are behind the renewed interest in refracturing," The Permian Basin Petroleum Association Magazine, 7 February 2017.
5. Barba B.: "Study Highlights Upside Of Refracturing Older Wells In Organic Shale Plays", Markets & Analytics, January 2023.
6. Fowler G., Zaghloul J., Jones D., Hall-Wiist L., Hopson D., Allen S., Picone M., Morales A., Marongiu Porcu M., McClure, M, Ratcliff D.: "A success story: Screening and optimizing refracs in the eagle ford," URTEC-3848875-MS presented at SPE/AAPG/SEG Unconventional Resources
7. Economides M. J., Hill D., Ehlig – Economides, C., Zhu, D., Petroleum Production Systems, Second Edition.
8. Moridis N., Lee W. J., Jochen V., Sim W., Blasingame T.: "Estimating Reserves and Tracking the Classification of Reserves and Resources Other than Reserves (ROTR) in Unconventional Reservoirs," URTEC-336 presented at Unconventional Resources Technology Conference held in Denver, Colorado, USA, 22-24 July 2019.

9. Technology Conference, Denver, Colorado, USA, June 2023.
10. Economides M.J., Oligney R., Valco P., Unified Fracture Design, 2002.
11. Economides M.J., Martin T., Modern Fracturing, 2008.
12. Downey M. W., Garvin J., Lagomarsino RC, Nicklin D. F., A Quick-look Determination of Oil-in-Place in Oil Shale Resource Plays.
13. Asquith G. B., Gibson C. R., Basic well log analysis for geologists, 1982.
14. Asquith G. B., Drager L., Saha S., "A New Approach To Estimating Sw In Carbonate Reservoir", The Log Analyst, Volume 34, Issue 03, May 1993.
15. Asquith G. B., Reservoir Producibility Index (RPI) From NMR Logs and the Analysis of Tight Oil Reservoirs, Unconventional Resources Technology Conference, July 24–26, 2017 Austin, Texas, USA.
16. Dalamarinis P., Radwan A., Ramanathan R., Ellafi A., Khanal S.: "Tailored Metal Oxide Nanoparticles-Based Fluids in Acid Restimulation Treatments Reverses Long-Term Hydrocarbon Decline: A Pilot Study in Wolfcamp (A) Formation, ATCE 2023, SPE-215039-MS
17. Dalamarinis P., Fusselman S., Hons C., Reese I., Schwin S., Nelle W., Reynolds R.: "High-Pressure Gas Lift (HPGL) as an Alternative to Electric Submersible Pumps (ESP) in Wolfcamp Unconventional Wells. An Operational, Economic, and Production Performance Comparison," SPE-219536-MS presented at SPE Artificial Lift Conference and Exhibition - Americas, The Woodlands, Texas, USA, August 2024.
18. McNeilly K., Smith A., Harms L. K., Schwin S., Nelle W., Reynolds R.: "Learnings from Successful Permian High Pressure Gas Lift Installations," SPE-219552-MS presented at SPE Artificial Lift Conference and Exhibition - Americas, The Woodlands, Texas, USA, August 2024.