Volver

A Case Study: New Self-Removing Diverter Application Immediate Operational Efficiencies and Enhanced Production Results

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ABSTRACT

The Vaca Muerta shale reservoir in Neuquén, Argentina is transitioning from exploration to development in certain acreage positions. Developing an unconventional resource using lessons learned from previously developed shale plays in other basins has illustrated the importance of balancing operational efficiency and enhancing well productivity. A successful lesson learned from North America with regards to operational efficiency and productivity has been the novel use of a self-removing diverter application (SRDA). This paper presents a case study, including formation information, wellbore data, stimulation procedures, engineering considerations, logistical challenges, operational efficiencies, production rates/volumes, and economic value created by SRDA in a multistage Vaca Muerta shale refracture stimulation.

Before applying fracture stimulation in source rock reservoirs, there are many technical services that need to be performed to complete a wellbore efficiently and effectively. A typical unconventional completion design requires the use of mechanical isolating plugs and multiple perforation clusters in each interval to effectively treat and isolate each stage interval during the fracture stimulation process. The economics for unconventional shale wells are heavily influenced by the completion process in regards to logistical challenges and necessary services. The application of SRDA and elimination of some or all of the wellbore interventions necessary when using conventional plug-and-perforating methods in a refracturing treatment in a harsh remote environment can reduce overall completion costs and the required timeframe significantly. In addition to improvements in operational efficiency, initial and sustained well production results were maintained and even enhanced.

SRDA provides the ability to continuously stimulate multiple stages within a single wellbore and to help ensure all of the intended perforation clusters receive effective stimulation by incorporating a diverting material that is 100% degradable with time and temperature. Fracturing with SRDA technology began in 2010; by April 2015, it had been applied in more than 16,000 fracturing treatments in every major unconventional basin in North America, including the Eagle Ford, Haynesville, Marcellus, Bakken, Niobrara, Woodford, Barnett, Wolfberry, Monterey shale, and Duvernay shale. Its use is continuing to grow in these settings and around the world (e.g., the pioneer application in Argentina's Vaca Muerta shale, the subject of this study).

SRDA has been used in a wide range of formations with a true vertical depth (TVD) from 3,500 to 15,000 ft and treated perforation clusters at over 20,000 ft measured depth (MD); it has been applied to new completions and used in refracturing operations in wells with bottomhole static temperatures (BHSTs) as high as 360°F.

Whether resulting from evolved completion designs, casing integrity issues, poor cluster efficiency leading to ineffective stimulation initially, or for increasing operational completion efficiency and feasibility, all multistage stimulation and refracturing treatments in the Vaca Muerta shale are potential candidates for optimization using SRDA.

INTRODUCTION

Worldwide, technically recoverable shale oil resources have been estimated at 345 billion barrels and 7,299 trillion cubic feet (Tcf) of shale gas resources. Since 2011, this number has grown by over 10% and is expected to continue to grow as new discoveries are made and drilling and completion methods optimize recovery factors. These latest figures for shale oil add approximately 11% to the most recent worldwide non-shale proved and unproved technically recoverable reserves resource assessment and 47% to the non-shale gas resources previously identified. Globally, 32% of the total estimated natural gas resources are in shale formations, while 10% of estimated oil resources are in shale or tight formations. (US Energy Information Administration, 2013). One country that has experienced substantial growth in development and advances in completion methodology, leading to growing estimates of shale reserve potential, is Argentina. Recoverable reserve estimates of more than 27 billion barrels of oil and an excess of 800 Tcf of gas, according to the US Energy Information Administration (2013), rank Argentina as the world's fourth largest reserve of shale oil, behind Russia, US, and China, and places it second only to China in shale oil reserves. This world-class shale gas and shale oil potential, possibly the most prospective outside of North America, lies primarily within the prolific Neuquén basin in the Vaca Muerta shale.

The resource potential of the Neuquén basin's Vaca Muerta shale has been estimated at technically recoverable shale gas and shale oil resources of 308 Tcf of gas and 16 billion barrels of oil and condensate from an in-place oil-equivalent estimate of 270 billion barrels (US Energy Information Administration, 2013). The play is estimated to encompass approximately 7.5 million acres (Figure 1) with an average estimated ultimate recovery (EUR) per well of 292,000 barrels of oil equivalent (BOE) (Wood Mackenzie, 2014). The vast resource potential, positive initial well results, growing logistics, and favorable regulatory environment has led to a surge in activity in the play, with several major oil companies investing in developing acreage, including Chevron, Shell, Total, ExxonMobil, Winthershall, and YPF, which is Argentina's national oil company and largest producer. YPF holds over 3,000,000 acres in the Vaca Muerta, approximately 40% of the play, and plans to meet the aggressive target of approximately 1,500 wells drilled through 2017. The majority of YPF's approximately 160 initial pilot wells was drilled in the Loma La Lata field in the oil-rich window of the play, with recorded initial production rates between 180 and 600 BOE/D (Figure 1) (Wood Mackenzie, 2014).

Continued infrastructure improvements, such as roads, water networks, and production facilities, in combination with an influx of stimulation equipment and more efficient proppant sourcing strategies, enables full-scale unconventional development, mirroring the rapid impactful development observed in the early days of US shale plays, such as the Eagle Ford, Haynesville, and Marcellus. These helped transform the dynamics of the US domestic energy market. The advancement of the unconventional drilling and completion learning curve has already benefited emerging plays, such as the Vaca Muerta. One such shale-focused technology, SRDA, continues to provide the flexibility, stimulation effectiveness, and operational efficiency required to generate favorable economics and return on investment from wide-spread acreage developments.

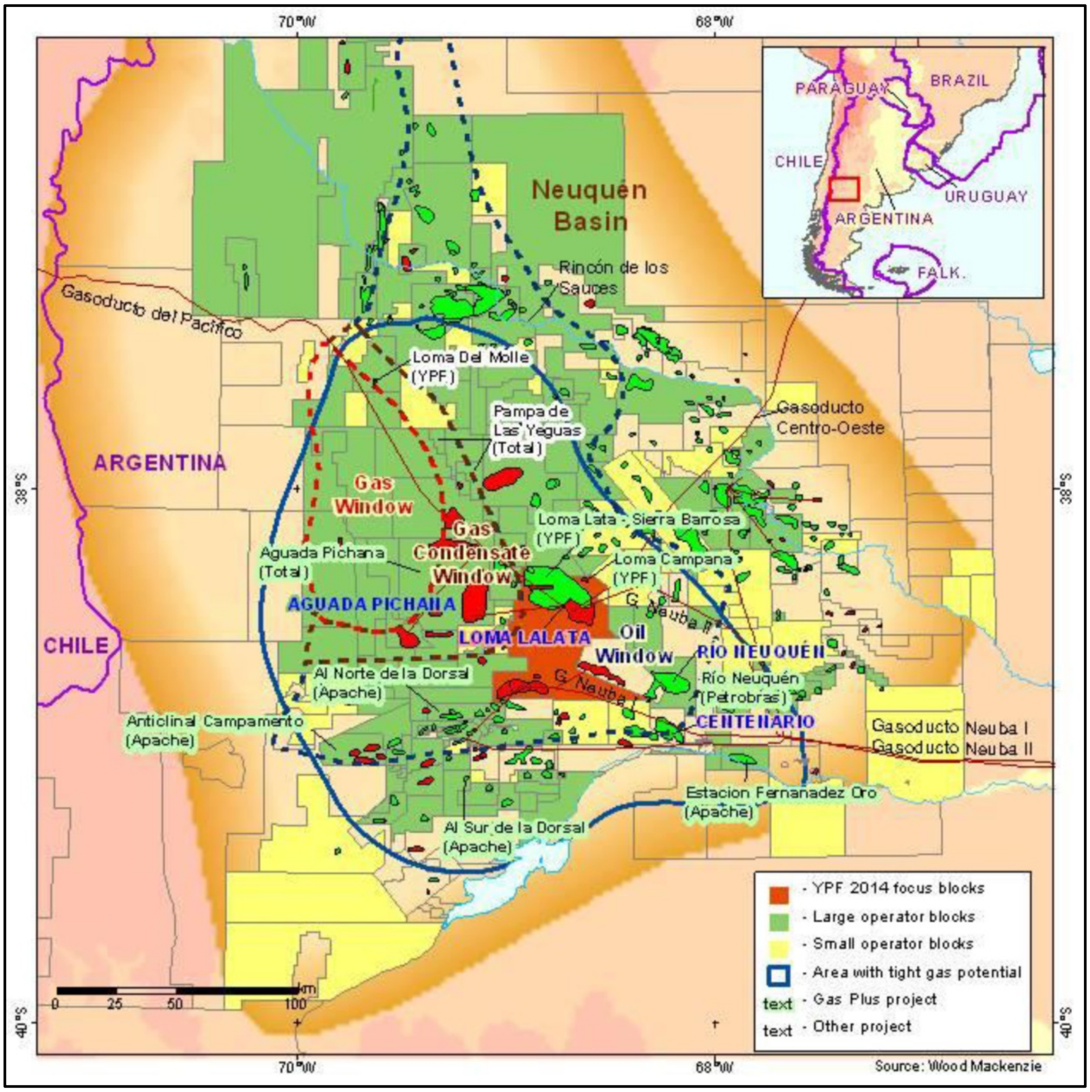


Figure 1— Vaca Muerta shale basin, Argentina, acreage blocks and oil and gas windows (Wood Mackenzie, 2014).

FORMATION INFORMATION

The Vaca Muerta formation is one of the primary source rocks in the prolific Neuquén basin located in the central western portion of Argentina, South America. It is classified as a Late Jurassic-Early Cretaceous deep marine deposit containing Type II kerogen and a high total organic carbon (TOC), ranging from 3 to 10%, an amount greater in comparison to the deeper Los Molles formation, the Neuquén basin, and other shales around the world.

Because of complex and varying depositional sequences and environments, its organic content, as well as mineralogy, changes across its areal and vertical distribution. The prospective area covers approximately 30,000 km^2 (7,413,154 acres), and reservoir thickness varies from SE toward the NW of the basin, ranging from absent to over 1,000 ft thick in the basin center. Depth to the top of the formation ranges from outcropping near the basin edges to the south to over 9,000 ft deep in the central syncline (Figure 2).

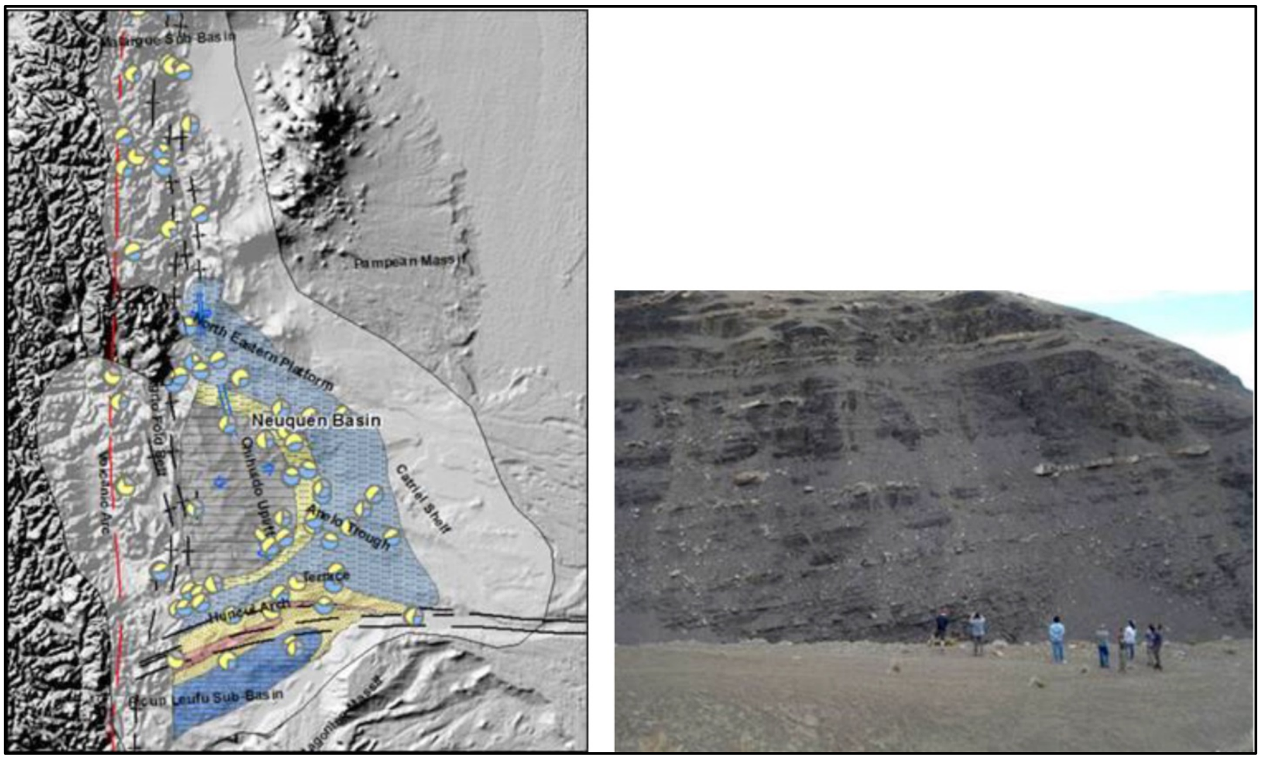


Figure 2—(Left) Structural environments controlled sediment deposition (Source YPF); (right) a view of an outcrop.

The Vaca Muerta formation is present across much of the Neuquén basin; however, intrinsic properties vary along it. With regards to organic richness, the formation presents very good to excellent actual average TOC values, especially at the lower-most section (Lower Vaca Muerta), with lower values of 3% basin wide, and higher values up to 10% from cores. Upper Vaca Muerta shows an actual average TOC between 2 and 4%, with peaks up to 5% in distal areas. This is a continuous high-TOC interval according to the measured cutting samples (on average).

The continuous thickness of the Vaca Muerta formation with TOC above 2% ranges from 90 ft at the basin's edges up to 1,400 ft at the center of the basin. The total marl thickness reaches 2,300 ft at the basin's center (Figure 3a). An upper section in the Vaca Muerta marls with TOC values below 2% is not shown on this map but could be of some interest with regards to the shale oil play.

Maturity windows, based on Ro data, show a consistent variation from 0.55% Ro at the edges of the basin to 2.7% Ro at the center of the basin. This implies a smooth variation of fluid content, from low gas/oil ratio (GOR) liquids at low maturity areas to dry gas at high maturity areas.

New production data and legacy well test data (Noguera, 2012) indicate the oil window to be in the 0.55 to 1.4 range, wet gas window in the 1.4 to 1.7 range, and dry gas window of 1.7 and above (Figure 3b).

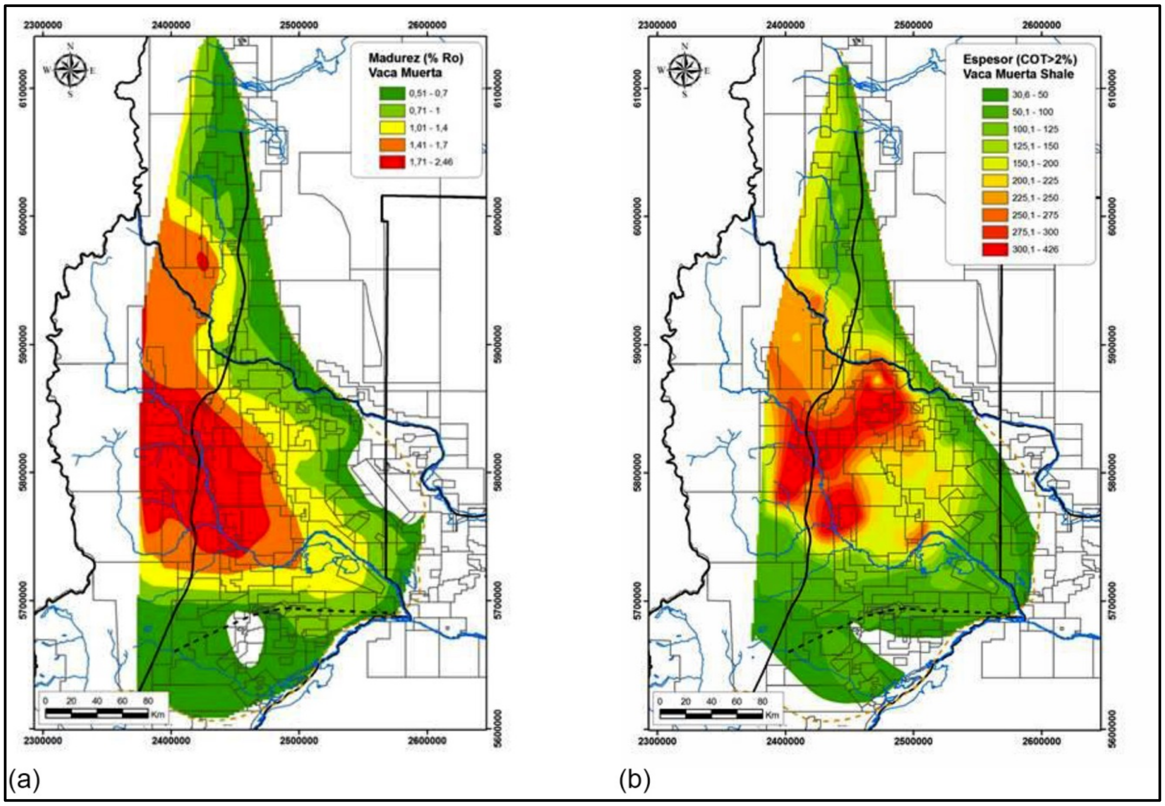


Figure 3— (a) Vaca Muerta TOC over 2% thickness isomap (Source YPF), (b) Vaca Muerta formation thermal maturity window (Source YPF).

From a mineralogy perspective, X-ray diffraction (XRD) data show low clay content, between 5 and 25%, and approximately 100% illite, with no expandable clay, in the area of study. In other parts of the basin, a high percentage of swelling clays was identified.

Quartz and carbonate contents vary according to the vertical position in the formation and the position in the basin. Quartz tends to be more abundant at the base of Vaca Muerta, decreasing as carbonate increases to the top of the formation. In distal areas, quartz and carbonate contents are approximately equal.

Based on the many different analyses performed and results of vertical pilot wells across the basin, it is observed that this shale reservoir offers a very high potential within its different facies (Garcia et al., 2013). The prospective depth for the Vaca Muerta shale averages 8,500 to 10,200 ft, has an average BHST of 240°F, and exhibits reservoir pressure up to 9,500 psi.

Proposed Challenge

A leading Vaca Muerta shale operator was considering available options for wells completed early in the play's development using experimental designs. Based on the current evolved completion design, the early completions might have been under-stimulated. If an efficient recompletion program with a successful restimulation technique could be identified and used, many wells could be reinvigorated. Candidate wells for the program were selected from the earliest pilot vertical completions in the Loma La Lata field between 2010 and 2011.

The unknown condition of the casing and perforations raised concerns about using mechanical barriers, such as bridge plugs or permanent ball sealers, to isolate portions of the interval. The use of SRDA helps enable a multitreatment approach to continuously stimulate the targeted interval. Because previously stimulated perforations can suffer from erosion and might no longer seal in the case of spherical geometries, the SRDA offers some distinct advantages compared to conventional ball sealers and other previously used diverting materials (Allison et al., 2011).

With the logistical challenges present in the Vaca Muerta shale at the time of the refracture, the concept of nonstop stimulating presented a major challenge and was unprecedented in this particular region of South America.

Engineering Considerations

The refracturing treatment was intended to inject fluid through the original perforations with no new clusters to be shot. With this goal in mind, a SRDA was chosen as the near-wellbore (NWB) biodegradable diverting system for the treatment. For refracturing, this technology allows previously stimulated and produced intervals to be simultaneously stimulated without the use of wellbore interventions. In some refracturing applications, additional perforation clusters are added to the existing sets (French et al., 2014), and SRDA can be used to squeeze low-pressure, produced, or depleted zones before pumping the first stage of the main treatment. The SRDA is designed to effectively stimulate a large treatment interval with multiple open perforation clusters through a series of treatments separated by diversion spacers. The bridging and isolation of the dominant clusters acquiring fluid initially, by means of the diversion material, create a differential pressure in the wellbore to redirect stimulation energy to untreated or subsequent clusters in the treatment interval. This can facilitate the breakdown of subsequent clusters encountering higher fracture and breakdown gradients (Ingram et al., 2014).

This mechanism of action allows a multi-treatment approach to stimulate only a portion of the open clusters at a time, flush the treatment, and then redirect fluid into new unstimulated clusters, in a continuous pumping operation, until the entire interval has been completed.

The multisized particle distribution of the SRDA material enables it to bridge off irregular geometries, such as eroded perforations in the casing and also in the NWB region of fractures (Figure 4). SRDA is compatible and unaffected at the surface in water- or acid-based fracturing fluid systems. It is self-removing in that it will reliably self-degrade through a chemical reaction over time and temperature, not requiring subsequent intervention. The specific SRDA material was chosen because it is compatible with most production chemicals, such as scale inhibitors, biocides, and tracers, as well as most fracturing fluid additives. The system uses existing fracturing equipment to deliver and place the diversion spacers. When the reservoir returns to its normal static temperature, SRDA begins the process of degradation. Temperature and water cause the material to degrade to a benign by-product with a slightly acidic pH, which can have a secondary benefit of aiding in the breaking and cleanup of stimulation fluid.

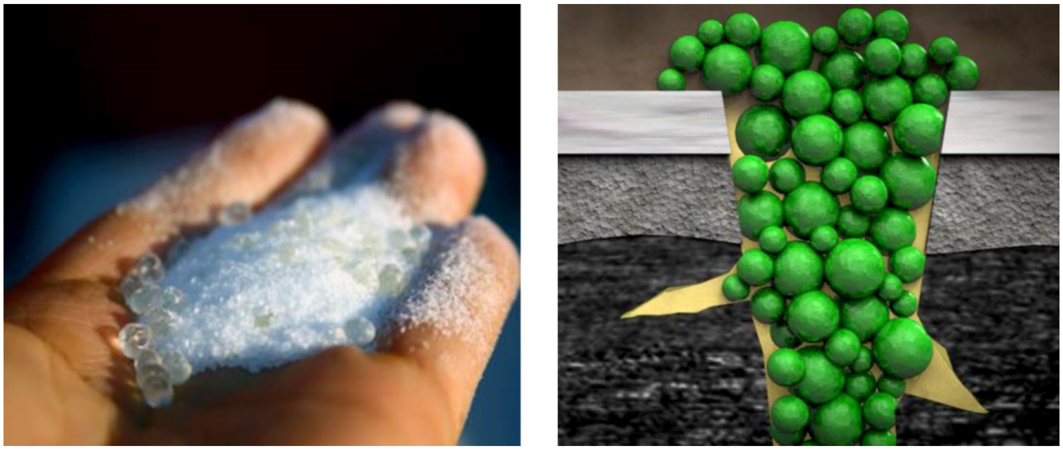


Figure 4—Multisized particles of SRDA material designed to effectively bridge at perforations and in the region behind them to divert fracturing fluid to other open clusters in the treatment interval.

Candidate Well A: Original Completion Data

The candidate well to be restimulated was a vertical cemented S-type well with a 4 1/2-in. P110 monobore casing. The well's total depth (TD) was approximately 10,200 ft (Figure 5).

The original stimulation treatment consisted of four stages, completed using a plug-and-perf technique. Two perforation clusters were designed for each interval, with the exception of Stage 1, where four clusters were shot. Perforations were shot with a 2 7/8-in. gun, had a shot density of 6 shots per foot (SPF) with 60° phasing, and used a deep penetrating style charge. To complete all stages, a total fluid volume of 1,145,080 gal and 1,342,000 lbm of proppant were pumped.

The original stimulation design presented differences between the four stage intervals, mostly resulting from trials of experimental well completions and fracturing designs. The designed fracturing rate varied between the stages, as 70, 40, 40, and 24 bbl/min were pumped, respectively. Fluid volumes and proppant mass for the original completion were standardized per foot of gross perforated interval in each stage, and the results are demonstrated in Figures 6 and 7. To accomplish this task, the gross perforated interval (top perforation – bottom perforation) for each stage was used and documented as perforation thickness (Figure 5).

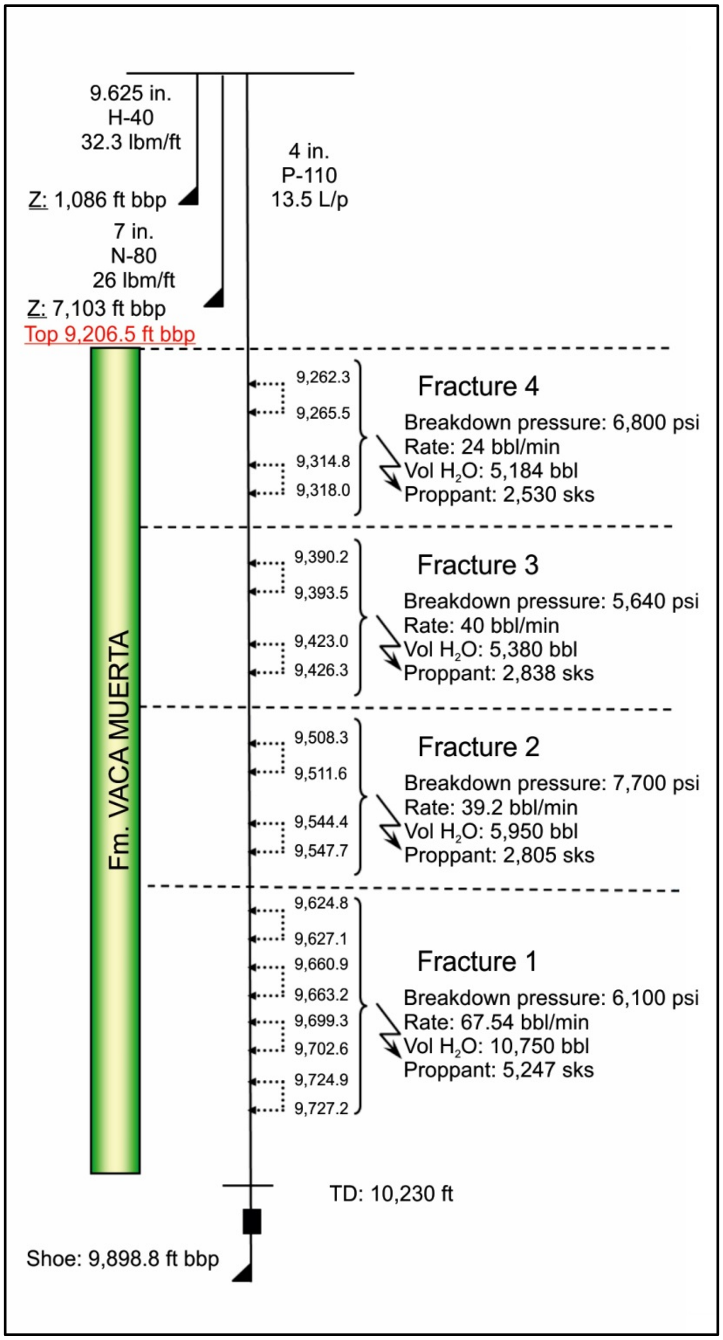
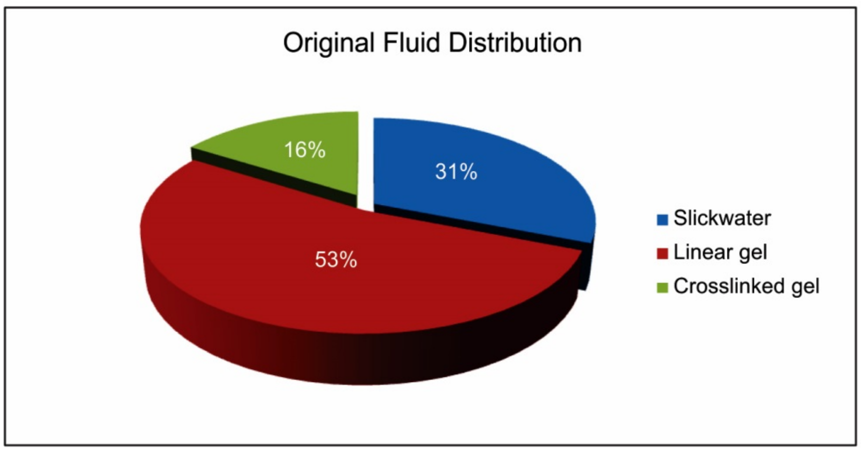


Figure 5—Candidate Well A original perforation scheme and wellbore schematic.

In terms of average fluid types between stages, 31% of the total fluid volume was slickwater, 53% corresponded to linear gel (guar), and only 16% was crosslinked (Figure 6). From a fluid perspective, the original completion design for candidate Well A is representative of the early experimental Loma La Lata field designs. This provided the opportunity to optimize the refracture stimulation treatment based on the new prominent hybrid stimulation design proven effective in the Loma La Lata field.

Stage	1	2	3	4
15% HCl Acid (gal)	2.000	2.000	2.000	2.000
Slickwater (gal)	133.116	74.576	57.325	83.293
Linear Gel (gal)	313.784	102.340	123.580	100.253
Crosslinked Gel (gal)	4.597	72.991	45.041	34.184
Total (gal)	451.496	249.907	225.946	217.731
Cumulative Total (gal)	1,145.080			
Perf Thickness	102	39	36	56
15% HCl Acid (gal/ft)	20	51	55	36
Slickwater (gal/ft)	1.300	1.894	1.588	1.493
Linear Gel (gal/ft)	3.065	2.599	3.424	1.797
Crosslinked Gel (gal/ft)	45	1.854	1.248	613

(a)



(b)

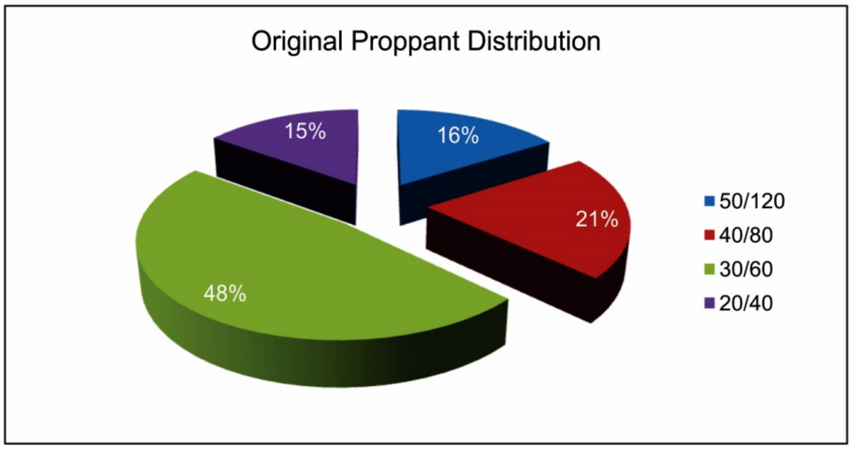
Figure 6—(a) Fluid distribution per foot of gross perforated interval (perf thickness) and (b) average total fluid distribution.

Comparisons of fluid designs for each stage indicate the main variance was the volume pumped per foot and the percentage of crosslinked gel used. For Stage 1, linear gel and slickwater were primarily pumped; Stages 2 and 3 had a higher percentage of crosslinked gel volume per foot of gross perforated interval. Stage 4 more closely matched the linear gel and slickwater-dominated design, with a fluid volume per foot significantly lower than the other stages.

Proppant distribution involved four meshes; a similar proportion of each was pumped in all four stages. Averaging the entire completion, 16% was 50/120 mesh, 21% was 40/80 mesh, 48% was 30/60 mesh, and 15% was 20/40 mesh (Figure 7). Based on this analysis, the proppant mesh size distribution and mass pumped per stage represents an early Loma La Lata design focusing on fracture conductivity and connectivity, as is present in the current Vaca Muerta vertical completion design, where the focus is on liquids production.

Stage	1	2	3	4
50/120 (lbm)	92.400	46.200	46.200	33.000
40/80 (lbm)	118.800	59.400	59.400	52.000
30/60 (lbm)	267.300	132.000	132.000	116.000
20/40 (lbm)	46.200	42.900	46.200	52.000
Total (lbm)	524.700	280.500	283.800	253.000
Cumulative Total (lbm)	1,342.000			
50/120 (lbm/ft)	964	1.173	1.280	592
40/80 (lbm/ft)	1.240	1.509	1.646	932
30/60 (lbm/ft)	2.790	3.353	3.657	2.080
20/40 (lbm/ft)	482	1.090	1.280	932

(a)



(b)

Figure 7—(a) Proppant distribution per foot of gross perforated interval and (b) average proppant mesh size distribution.

Candidate Well B: Original Completion Data

The candidate Well B for restimulation was a vertical cemented well, with a 5-in. N-80 monobore casing. The well TD reached approximately 9,100 ft (Figure 8).

In 2010, two stimulation treatments were performed on this well. Originally, there were three zones shot, with a 1 m cluster, 1.5 m cluster, and three 1 m clusters, respectively.

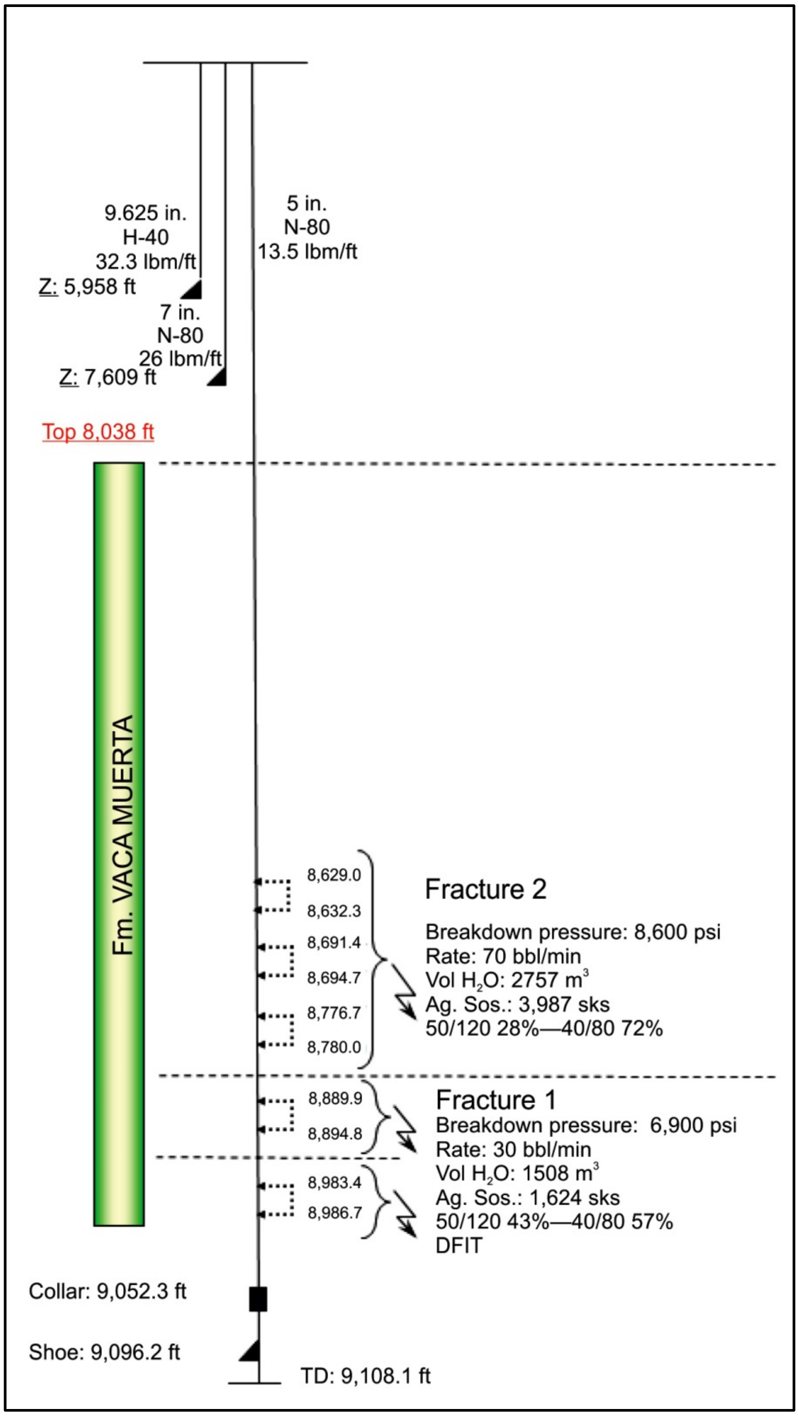


Figure 8—Candidate Well B original perforation scheme and wellbore schematic.

After testing Zone 1 (8,983.4 to 8,986.7 ft), the zone was isolated without being stimulated, first by setting a mechanical plug and second by applying a cement plug using the dump bailer technique. Zone 2 was perforated and tested. New perforations were then added, extending the perforated thickness from 3.5 to 5 ft. Shot density was 6 SPF, 60° phasing.

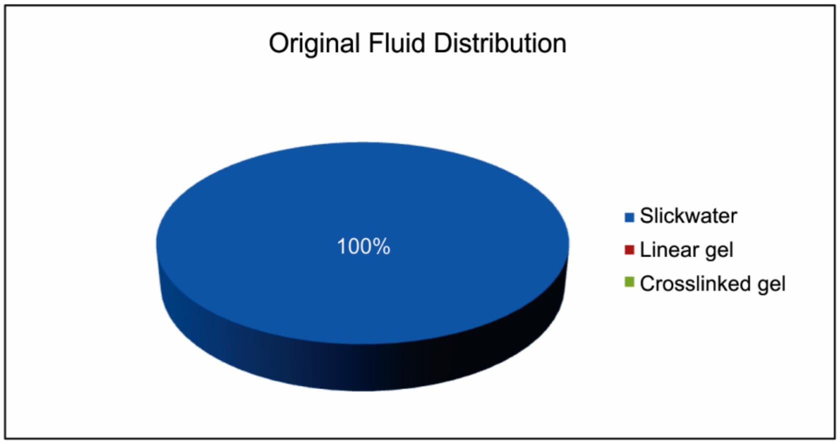
Stimulation was performed at 30 bbl/min, having pumped a total fluid volume of 400,000 gal. The second treatment was placed over three clusters and was performed at 70 bbl/min, pumping almost 730,000 gal of fluid. The fracture gradient was similar in both stages, averaging 1.03 psi/ft; surface treatment pressure averaged 6,500 to 7,200 psi between stages.

Similar meshes were used in both treatments. Only 50/120 and 40/80 mesh were pumped, although proppant distribution was different among stages. Treatment 1 contained 1,624 sks, where 30% corresponded to 50/120 mesh and 70% to 40/80 mesh. Proppant distribution was more equivalent for Stage 2. A total of 3,987 sks were pumped, where 45% and 57% corresponded to 50/120 and 40/80 mesh, respectively.

Regarding fluids, all treatments were performed by pumping only water with friction reducer (slickwater). Once again and for documentation, fluid volumes and proppant mass for the original completion were standardized per foot of gross perforated interval in each stage, considering gross perforated interval (top perforation – bottom perforation) for each stage was used and documented as perforation thickness (Figures 9 and 10).

Stage	1	2
15% HCl Acid (gal)	1,000	2,000
Slickwater (gal)	398,371	728,322
Linear Gel (gal)	0	0
Crosslinked Gel (gal)	0	0
Total (gal)	399,371	730,322
Cumulative Total (gal)	1,129,694	
Perf Thickness	5	10
15% HCl Acid (gal/ft)	204	204
Slickwater (gal/ft)	81,300	74,319
Linear Gel (gal/ft)	0	0
Crosslinked Gel (gal/ft)	0	0

(a)

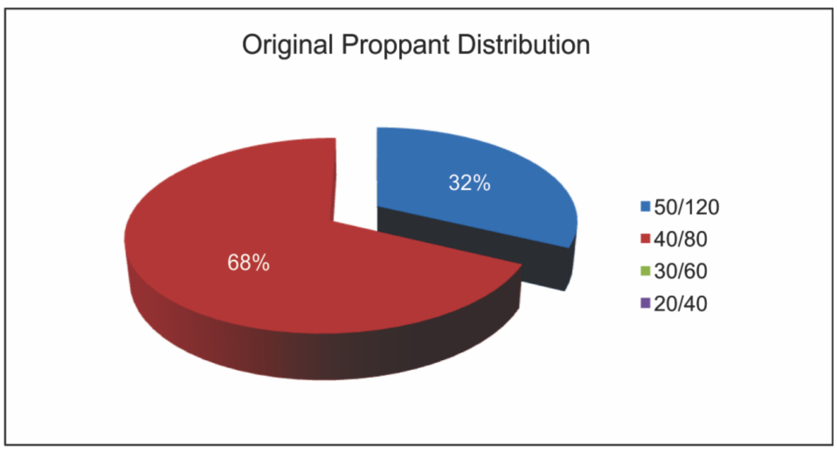


(b)

Figure 9 (a) Fluid distribution per foot of gross perforated interval (perf thickness) and (b) average total fluid distribution.

Stage	1	2
50/120 (lbm)	69,300	110,520
40/80 (lbm)	93,080	288,150
30/50 (lbm)	0	0
20/40 (lbm)	0	0
Total (lbm)	162,380	398,670
Cumulative Total (lbm)	561,050.00	
Perf Thickness	5	10
50/120 (lbm/ft)	14,143	11,278
40/80 (lbm/ft)	18,996	29,403
30/50 (lbm/ft)	0	0
20/40 (lbm/ft)	0	0

(a)



(b)

Figure 10—(a) Proppant distribution per foot of gross perforated interval and (b) average proppant mesh size distribution

STIMULATION PROCEDURE

For an efficient recompletion operation, it was necessary to temporarily plug the perforation clusters after the initial and subsequent stages in the treatment. To accomplish this, stages were designed to stimulate two clusters at a time. This actually increased the likelihood of effectively blocking the preferential or dominant fluid entries so better diversion could occur, resulting in better stimulation across the entire vertical column.

Logistical Challenges and Execution

Continuous operations in the current logistically sparse environment of the Neuquén basin require detailed planning for a successful well stimulation execution. All proppant, water, and materials had to be transported to and stored on location before the start of the stimulation process. Gathering supplies was not the main concern, but placing them in a location not originally planned for such operations was a challenge. The SRDA technology required hydraulic horsepower (HHP) backup because of long pumping hours and a standalone setup composed of a blender, two isolated pumps with special valve inserts, and a ground manifold with a high-pressure treating line connected directly to the wellhead for injecting the SRDA technology into the high-pressure fracture stream on-the-fly (Figure 11).

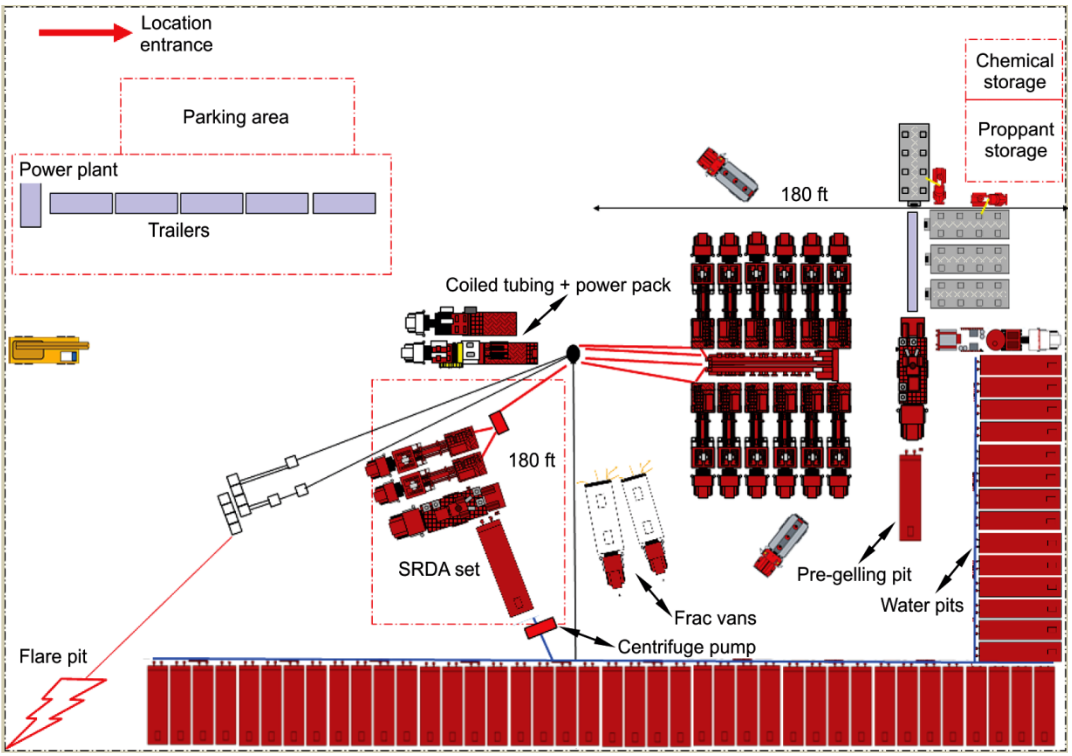


Figure 11—Equipment layout of candidate Well A SRDA location.

Because the intrinsic characteristic of the material is designed to bridge and seal orifices, pumping it through the main fracturing equipment is not recommended. Instead, a standalone setup is used solely for injecting the diversion material into the wellbore and continues to inject clean fluid for the displacement of the diversion spacer into the treatment interval. After the diversion spacer reaches the treatment interval and a pressure response is observed, the standalone SRDA pumps are taken offline for the remainder of the proceeding stage.

The SRDA material could not be injected immediately behind the completion of the 20/40 mesh proppant stage on surface because of rate limitations. If the SRDA material is seated at high rates, there is a potential risk of ineffective bridging and sealing of the dominant perforation clusters acquiring fluid. With this knowledge, a clean fluid spacer volume of approximately 50 bbl was designed and pumped after the completion of the last 20/40 mesh proppant stage on surface (from the point when proppant concentration fell to zero at the wellhead) until the injection of the SRDA technology into the fracturing stream. The clean spacer volume was minimized as much as possible to reduce the amount of over-flush volume of the clusters being fractured during the preceding treatment.

Consequently, timing and injection of the diversion spacer was defined to use precise maneuvers to minimize over-flushing while also allowing the final and maximum proppant concentration from the preceding treatment to be placed into the fracture at the designed stimulation rate. Additionally, the diversion spacer delivered an effective concentration and seating rate for the SRDA material. Operationally, when the last proppant concentration was blended at surface, it was necessary for the two standalone SRDA pumps to begin pumping clean fluid. Simultaneously, in the main stimulation set, the pumping rates had to be reduced by the same HHP to allow the treatment to maintain the constant desired stimulation rate. Once the two rates were stabilized with a constant split flow rate between them and a minimum of 50 bbl of clean fluid after the wellhead proppant concentration fell to zero, the designed amount of SRDA was placed into the standalone blender tub and injected into the well.

When the SRDA technology reaches the perforations, a surface pressure increment is observed. As a consequence of sealing off sets of perforations and blocking the dominant fluid path, the system accumulates energy, raising the bottomhole treating pressure (BHTP) until fractures can be initiated at new clusters. When the successive perforation clusters break down, surface pressure begins decreasing. At that time, the fracturing rate is increased, and the second treatment in the series begins (Figure 12).

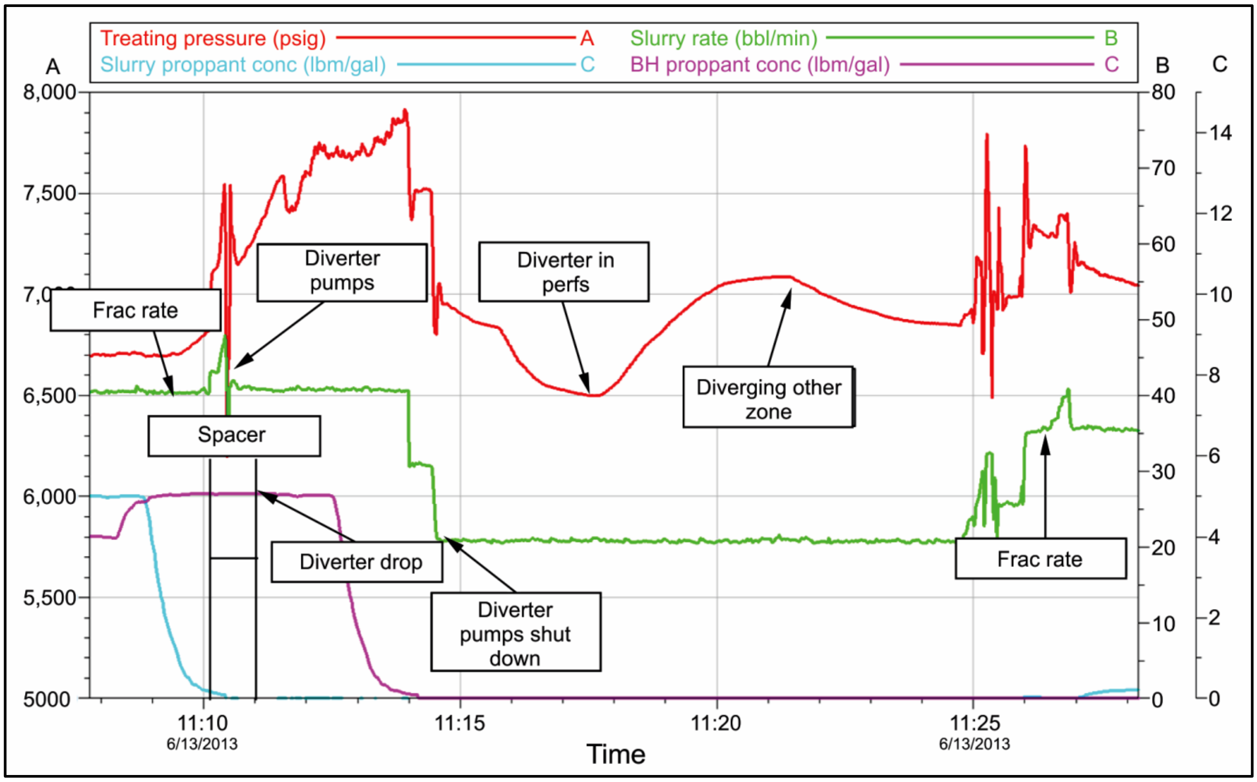


Figure 12—End of Treatment 1 and injection of the first diversion spacer of the refracturing SRDA.

Candidate Well A Recompletion

The new stimulation design for the recompletion of candidate Well A represented the new advanced hybrid design focused on liquid hydrocarbon production that has become prominent in the Loma La Lata field and was customized for the SRDA application.

Table 1 presents the refracture stimulation pump schedule, which was common for all five stages. After completion of Stage 1, the first diversion spacer was designed to be pumped in the wellbore to divert the trailing treatment Stage 2 fluids into new untreated perforation clusters. Notice that Stage 2 is designed to begin immediately after Stage 1, without stopping the pumping operation (Figure 12).

Stage	Step Name	Pump Rate (bbl/min)	Fluid Type	Fluid Volume (gal)	Prop Conc (ppa)	Prop Type	Prop Mass (lbm)	Slurry Volume (bbl)	Pump Time (min)
	Break Down	5	Slickwater	500	0.00	--	0	12	2.40
	Acid	5	15% HCl Acid	2,000	0.00	--	0	48	9.60
	SDRT	40	Slickwater	20,000	0.00	--	0	476	11.90
	Shut in	0	--	0	0.00	--	0	0	10.00
Stage 1	Pad	40	Slickwater	10,000	0.00	--	0	238	5.95
	0.30 lbm/gal	40	Slickwater	8,000	0.30	50/120	2,400	193	4.83
	0.60 lbm/gal	40	Slickwater	9,000	0.60	50/120	5,400	219	5.48
	1.00 lbm/gal	40	Slickwater	10,000	1.00	50/120	10,000	247	6.18
	1.00 lbm/gal	40	Slickwater	7,000	1.00	40/80	7,000	173	4.33
	1.50 lbm/gal	40	Linear gel	7,000	1.50	40/80	10,500	176	4.40
	2.00 lbm/gal	40	Linear gel	7,000	2.00	40/80	14,000	179	4.48
	2.00 lbm/gal	40	Linear gel	7,000	2.00	30/60	14,000	179	4.48
	2.50 lbm/gal	40	Linear gel	8,000	2.50	30/60	20,000	208	5.20
	3.00 lbm/gal	40	Crosslinked gel	12,000	3.00	30/60	36,000	317	7.93
	3.50 lbm/gal	40	Crosslinked gel	17,000	3.50	30/60	59,500	457	11.43
	3.50 lbm/gal	40	Crosslinked gel	13,000	3.50	20/40	45,500	350	8.75
	4.00 lbm/gal	40	Crosslinked gel	8,000	4.00	20/40	32,000	219	5.48
	5.00 lbm/gal	40	Crosslinked gel	5,000	5.00	20/40	25,000	141	3.53
SRDA	Spacer	40	Linear gel	1,000	0.00	--	0	24	0.60
	0.80 lbm/gal	40	Linear gel	500	0.80	SRDA	400	13	0.33
	Flush	40	Slickwater	5,000	0.00		0	119	2.98
	Flush	15	Slickwater	2,000	0.00		0	48	3.20
Stage 2	Pad	40	Slickwater	10,000	0.00	--	0	238	5.95
	0.30 lbm/gal	40	Slickwater	8,000	0.30	50/120	2,400	193	4.83
	0.60 lbm/gal	40	Slickwater	9,000	0.60	50/120	5,400	219	5.48
	1.00 lbm/gal	40	Slickwater	10,000	1.00	50/120	10,000	247	6.18
	1.00 lbm/gal	40	Slickwater	7,000	1.00	40/80	7,000	173	4.33
	1.50 lbm/gal	40	Linear gel	7,000	1.50	40/80	10,500	176	4.40
	2.00 lbm/gal	40	Linear gel	7,000	2.00	40/80	14,000	179	4.48
	2.00 lbm/gal	40	Linear gel	7,000	2.00	30/60	14,000	179	4.48
	2.50 lbm/gal	40	Linear gel	8,000	2.50	30/60	20,000	208	5.20
	3.00 lbm/gal	40	Crosslinked gel	12,000	3.00	30/60	36,000	317	7.93
	3.50 lbm/gal	40	Crosslinked gel	17,000	3.50	30/60	59,500	457	11.43
	3.50 lbm/gal	40	Crosslinked gel	13,000	3.50	20/40	45,500	350	8.75
	4.00 lbm/gal	40	Crosslinked gel	8,000	4.00	20/40	32,000	219	5.48
	5.00 lbm/gal	40	Crosslinked gel	5,000	5.00	20/40	25,000	141	3.53
SRDA	Spacer	40	Linear gel	1,000	0.00	--	0	24	0.60
	0.80 lbm/gal	40	Linear gel	500	0.80	SRDA	400	13	0.33
	Flush	40	Slickwater	5,000	0.00		0	119	2.98
	Flush	15	Slickwater	2,000	0.00		0	48	3.20
Stage 3	Pad	40	Slickwater	10,000	0.00	--	0	238	5.95
	0.30 lbm/gal	40	Slickwater	8,000	0.30	50/120	2,400	193	4.83
	0.60 lbm/gal	40	Slickwater	9,000	0.60	50/120	5,400	219	5.48
	1.00 lbm/gal	40	Slickwater	10,000	1.00	50/120	10,000	247	6.18
	1.00 lbm/gal	40	Slickwater	7,000	1.00	40/80	7,000	173	4.33
	1.50 lbm/gal	40	Linear gel	7,000	1.50	40/80	10,500	176	4.40

Table 1—Pump schedule for a total of five stages.

The new stimulation design consisted of 640,617 gal of fluid, representing a 56% reduction from the original design. The proppant amount was increased slightly over the original completion, but the main optimization was in proppant mesh size distribution, with larger percentages of 20/40 and 30/50 mesh to match the success of the advanced hybrid design. Therefore, less fluid and approximately equal proppant mass imply a higher average proppant concentration per foot of reservoir. The original treatment pumped an average proppant concentration of 1.23 lbm/gal, while the average proppant concentration of the refracture treatment was 2.20 lbm/gal.

Figure 13 shows a comparison between applied fracture designs.

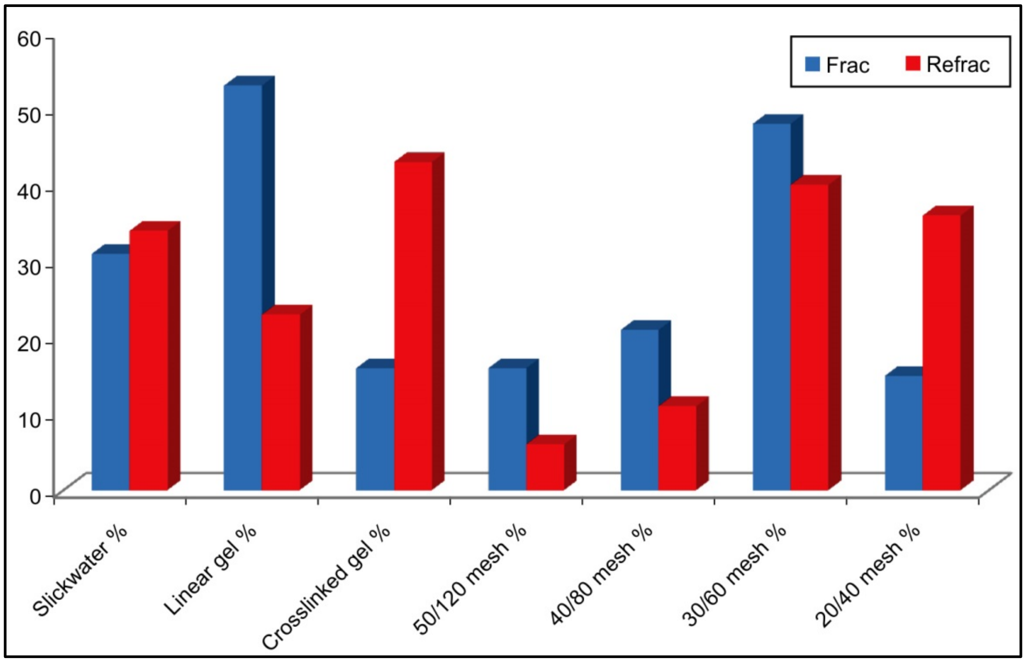


Figure 13—Comparison between the original completion and the refracture.

Figure 14 shows fluid and proppant distribution per stage.

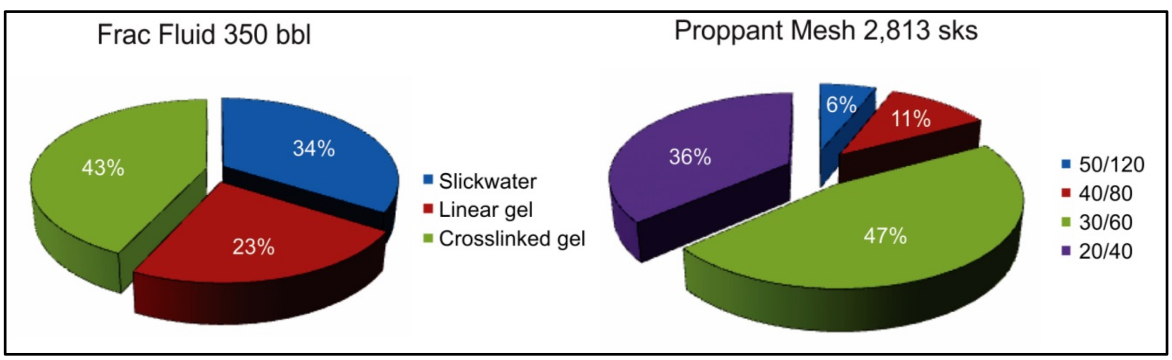


Figure 14—Fluid and proppant distribution per stage of the refracture treatment.

Candidate Well B Recompletion

As a refracture candidate, Well B presented the opportunity for application of a custom design, as well as the addition of new zones for completion. The completion program comprised three refracture treatments, isolated by two diverter batches. The recompletion stage also included one new perforation between old clusters (8,841.5 to 8,845.2 ft). After setting a mechanical plug above the refractured area, two new plug-and-perf stages could be added to the well.

Compared to the original treatment, final proppant concentration was increased, and a higher percentage of 20/40 mesh was pumped. Fluid distribution was adapted for the newer designs, including both linear and crosslinked gel (Figure 15).

Based on the experience gained in the first well, the diverter application was changed for this well. A different, smaller-mesh size diverter was mixed with the traditional diverter and pumped during the SRDA. Successful case histories in the Rocky Mountain region added this product to traditional SRDA.

The SRDA amount per drop, as well as the seat rate, led to the design of a successful diversion schedule. The first treatment had higher rates than the others, and it was expected to break into multiple clusters. Proceeding one step further to achieve diversion, 70% of the total amount required to plug the perforations was pumped on the first NWB diversion.

Table 2 shows the refracture stimulation pump schedule. Similar to the previous candidate well, after the completion of Stage 1, the first diversion spacer was pumped in the wellbore to divert the tailing treatment, Stage 2, without stopping pumping at any time.

Stage	Step Name	Pump Rate (bbl/min)	Fluid Type	Fluid Volume (gal)	Prop Conc (ppa)	Prop Type	Prop Mass (lbm)	Slurry Volume (bbl)	Pump Time (min)
	Break Down	3	Slickwater	500	0.00		0	12	4.00
	Acid	5	15% HCl Acid	2,000				48	9.52
	SDRT	70	Slickwater	15,000	0.00		0	357	5.10
	Shut In	0		0	0.00		0	0	10.00
	Pad	70	Slickwater	30,000	0.00		0	714	10.20
	0.30 lbm/gal	70	Slickwater	16,000	0.30	100	4,800	386	5.51
	0.60 lbm/gal	70	Slickwater	16,000	0.60	100	9,600	391	5.59
	1.00 lbm/gal	70	Linear gel	16,000	1.00	100	16,000	398	5.69
	1.00 lbm/gal	70	Linear gel	13,000	1.00	40/70	13,000	324	4.63
	1.50 lbm/gal	70	Linear gel	13,000	1.50	40/70	19,500	331	4.73
	2.00 lbm/gal	70	Linear gel	13,000	2.00	40/70	26,000	338	4.83
Stage 1	2.00 lbm/gal	70	Crosslinked gel	12,000	2.00	30/50	24,000	312	4.46
	2.50 lbm/gal	70	Crosslinked gel	12,000	2.50	30/50	30,000	318	4.54
	3.00 lbm/gal	70	Crosslinked gel	12,000	3.00	30/50	36,000	325	4.64
	3.50 lbm/gal	70	Crosslinked gel	11,000	3.50	30/50	38,500	304	4.34
	3.50 lbm/gal	70	Crosslinked gel	10,000	3.50	20/40	35,000	268	3.83
	4.00 lbm/gal	70	Crosslinked gel	9,000	4.00	20/40	36,000	245	3.50
	4.50 lbm/gal	70	Crosslinked gel	7,000	4.50	20/40		193	2.76
	5.00 lbm/gal	70	Crosslinked gel	5,000	5.00	20/40	25,000	140	2.00
	Spacer	70	Linear gel	500	0.00		0	12	0.17
SRDA	**1.00 lbm/gal**	**70**	**Linear gel**	**1,838**	**1.00**	**SRDA**	**1,838**	**48**	**0.69**
	Flush	70	Slickwater	4,114	0.00		0	98	1.40
	Flush	30	Slickwater	2,000	0.00		0	48	1.60
	Pad	60	Slickwater	20,000	0.00		0	476	7.93
	0.30 lbm/gal	60	Slickwater	14,000	0.30	100	4,200	338	5.63
	0.60 lbm/gal	60	Slickwater	14,000	0.60	100	8,400	342	5.70
	1.00 lbm/gal	60	Linear gel	14,000	1.00	100	14,000	349	5.82
	1.00 lbm/gal	60	Linear gel	12,000	1.00	40/70	12,000	299	4.98
	1.50 lbm/gal	60	Linear gel	12,000	1.50	40/70	18,000	306	5.10
	2.00 lbm/gal	60	Linear gel	12,000	2.00	40/70	24,000	312	5.20
Stage 2	2.00 lbm/gal	60	Crosslinked gel	10,000	2.00	30/50	20,000	260	4.33
	2.50 lbm/gal	60	Crosslinked gel	10,000	2.50	30/50	25,000	265	4.42
	3.00 lbm/gal	60	Crosslinked gel	10,000	3.00	30/50	27,000	271	4.52
	3.50 lbm/gal	60	Crosslinked gel	9,000	3.50	30/50	28,000	248	4.13
	3.50 lbm/gal	60	Crosslinked gel	8,000	3.50	20/40	24,500	214	3.57
	4.00 lbm/gal	60	Crosslinked gel	7,000	4.00	20/40	24,000	191	3.18
	4.50 lbm/gal	60	Crosslinked gel	6,000	4.50	20/40	22,500	166	2.77
	5.00 lbm/gal	60	Crosslinked gel	5,000	5.00	20/40	25,000	140	2.33
	Spacer	60	Linear gel	500	0.00		0	12	0.20
SRDA	**1.00 lbm/gal**	**60**	**Linear gel**	**500**	**1.00**	**SRDA**	500	**13**	**0.22**
	Flush	60	Slickwater	4,114	0.00		0	98	1.63
	Flush	30	Slickwater	2,000	0.00		0	48	1.60

Table 2—Refracture pump schedule for a total of three stages.

The new stimulation design for the refractured zone consisted of 520,000 gal of fluid, representing a 54% reduction compared to the original design. The proppant amount was increased more than 50% from the original completion, reaching over 850,000 lbm. The main optimization, however, was in proppant mesh size distribution; larger percentages of 20/40 and 30/60 mesh were used (Figure 16). Consequently, less fluid and an increased proppant mass imply a higher average proppant concentration per foot of reservoir.

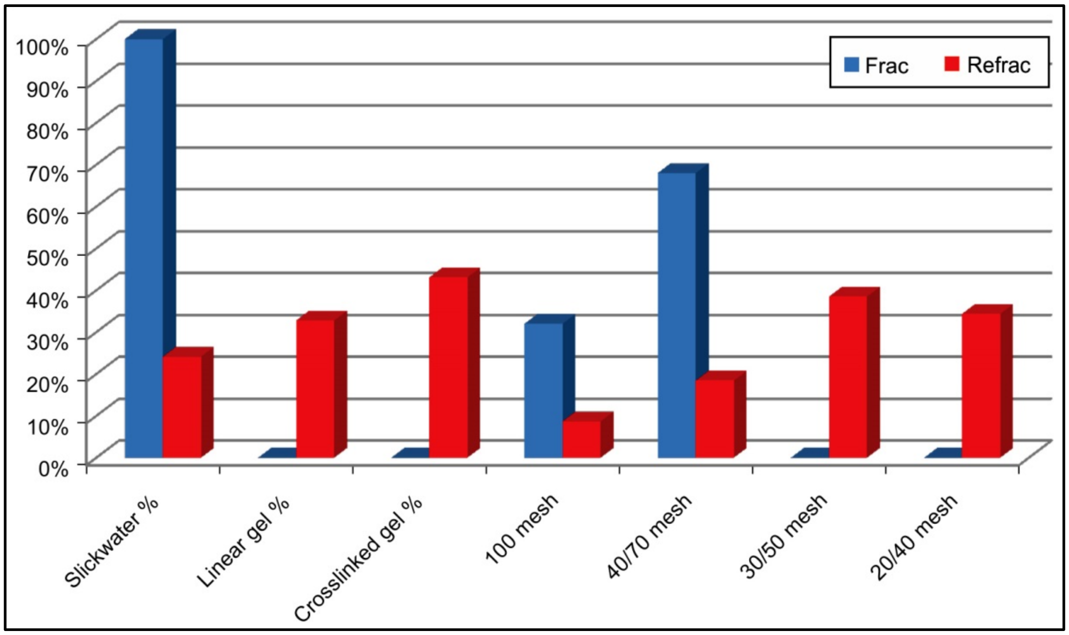


Figure 15—Comparison between the original completions and the refracture.

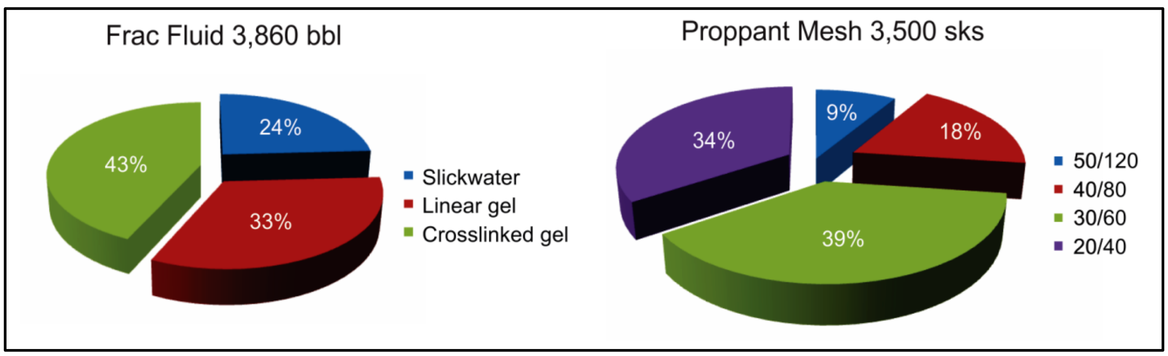


Figure 16—Fluid and proppant distribution per stage of the refracture treatment.

For the new zones, two plug-and-perf treatments were completed using hybrid designs (Table 3). Each treatment was composed of 507,300 lbm of proppant (100, 40/70, 30/50, and 20/40) and 308,400 gal of fluid (slickwater, linear gel, and crosslinked gel).

Step Name	Pump Rate (bbl/min)	Fluid Type	Fluid Volume (gal)	Prop Conc (ppa)	Prop Type	Prop Mass (lbm)	Slurry Volume (bbl)	Pump Time (min)
Break Down	3	Slickwater	500	0.00		0	12	3.97
Acid	5	15% HCl Acid	2,000					0.00
SDRT	60	Slickwater	20,000	0.00		0	476	7.93
Shut In	0		0	0.00		0	0	10.00
Pad	60	Slickwater	30,000	0.00		0	714	11.90
0.30 lbm/gal	60	Slickwater	22,000	0.30	100	6,600	531	8.85
0.60 lbm/gal	60	Slickwater	22,000	0.60	100	13,200	538	8.97
1.00 lbm/gal	60	Slickwater	30,000	1.00	100	30,000	747	12.45
1.00 lbm/gal	60	Linear gel	20,000	1.00	40/70	20,000	498	8.30
1.50 lbm/gal	60	Linear gel	23,000	1.50	40/70	34,500	586	9.77
2.00 lbm/gal	60	Linear gel	26,000	2.00	40/70	52,000	677	11.28
2.00 lbm/gal	60	Linear gel	18,000	2.00	30/50	36,000	468	7.80
2.50 lbm/gal	60	Crosslinked gel	17,000	2.50	30/50	42,500	451	7.52
3.00 lbm/gal	60	Crosslinked gel	17,000	3.00	30/50	51,000	460	7.67
3.50 lbm/gal	60	Crosslinked gel	17,000	3.50	30/50	59,500	469	7.82
4.00 lbm/gal	60	Crosslinked gel	14,000	4.00	30/50	56,000	394	6.57
4.00 lbm/gal	60	Crosslinked gel	10,000	4.00	20/40	40,000	272	4.53
4.50 lbm/gal	60	Crosslinked gel	8,000	4.50	20/40	36,000	221	3.68
5.00 lbm/gal	60	Crosslinked gel	6,000	5.00	20/40	30,000	168	2.80
Flush	60	Slickwater	5,935	0.00		0	141	2.35
			308,435.000			**507,300**	**7811**	**144**

15% HCL	2,000	gal	8	m^3
Slickwater	130,435	gal	494	m^3
Linear gel	87,000	gal	329	m^3
Crosslinked gel	89,000	gal	337	m^3
Total	308,435	gal	1168	m^3

100	49,800	lbm
40/70	106,500	lbm
30/50	245,000	lbm
20/40	106,000	lbm
Total	507,300	lbm

10	%PAD
1.64	ppa prom
2.40	Hours

Table 3—Plug-and-perf pump schedule for a total of two stages.

OPERATIONAL EFFICIENCIES

Candidate A

In total, five stimulation treatments were successfully placed over seven hours of continuous pumping, which included four applications of the SRDA technology to separate the treatments (Figure 17). Pressure responses created by the temporary plugging of the perforations and breakdown of new clusters are noted in the pressure charts.

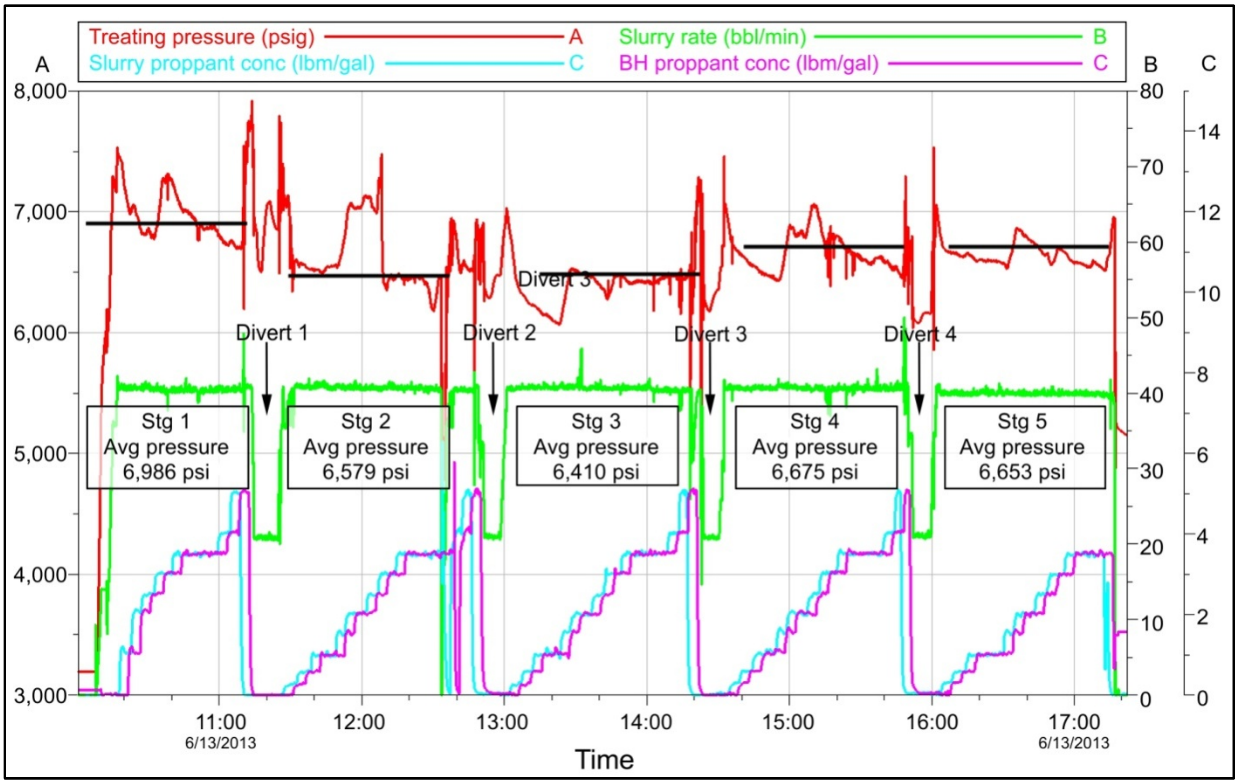


Figure 17—Candidate A multistage fracture chart.

Each diverter stage resulted in a pressure increase of 90 to approximately 600 psi. Also, varying surface pressure trends and magnitudes were observed in all five stages, suggesting that effective diversion occurred at the clusters, and additional areas were stimulated following each diversion. If the same clusters were stimulated on the subsequent stage following a diversion spacer, as in the previous treatment, a flat BHTP trend would be expected. If diversion occurred, and the original treatment area was simply reduced with no new areas broken down, an increase in pressure would be expected resulting from the additional entry friction; however, a flat pressure trend would still be observed, absent of breakdown responses post-diversion and upon rate establishment of the proceeding stage.

On the latter two treatments, the similar but higher overall treating pressure trend could indicate treatment of higher-stress rock, which is a possible reason why it was not the preferential zone initially. Additionally, the trend could indicate a smaller number of clusters being treated. Both explanations would require the plugging of a portion of the initially dominant clusters. The BHTP reached during diversion and sealing of the previous clusters potentially allows for not only higher stress rock to be broken down but also for overcoming some of the natural stress shadowing that is present while pumping into multiple clusters.

Table 4 presents SRDA injection analysis of Treatments 1 through 4.

Drops	1	2	3	4
SRDA Amount (lbm)	400	400	400	500
Concentration (lbm/gal)	0.7	1	0.65	0.85
Rate at Perfs (bbl/min)	20	20	20	20
ΔP (psi)	578	185	184	90
Spacer Size (gal)	2,300	1,500	3,350	1,500

Table 4—Diversion spacer statistics.

Candidate B

Execution of this completion ended prematurely because of a screenout at the end of Stage 2 (Figure 18). Two out of three fractures and only one SRDA application were completed on this well.

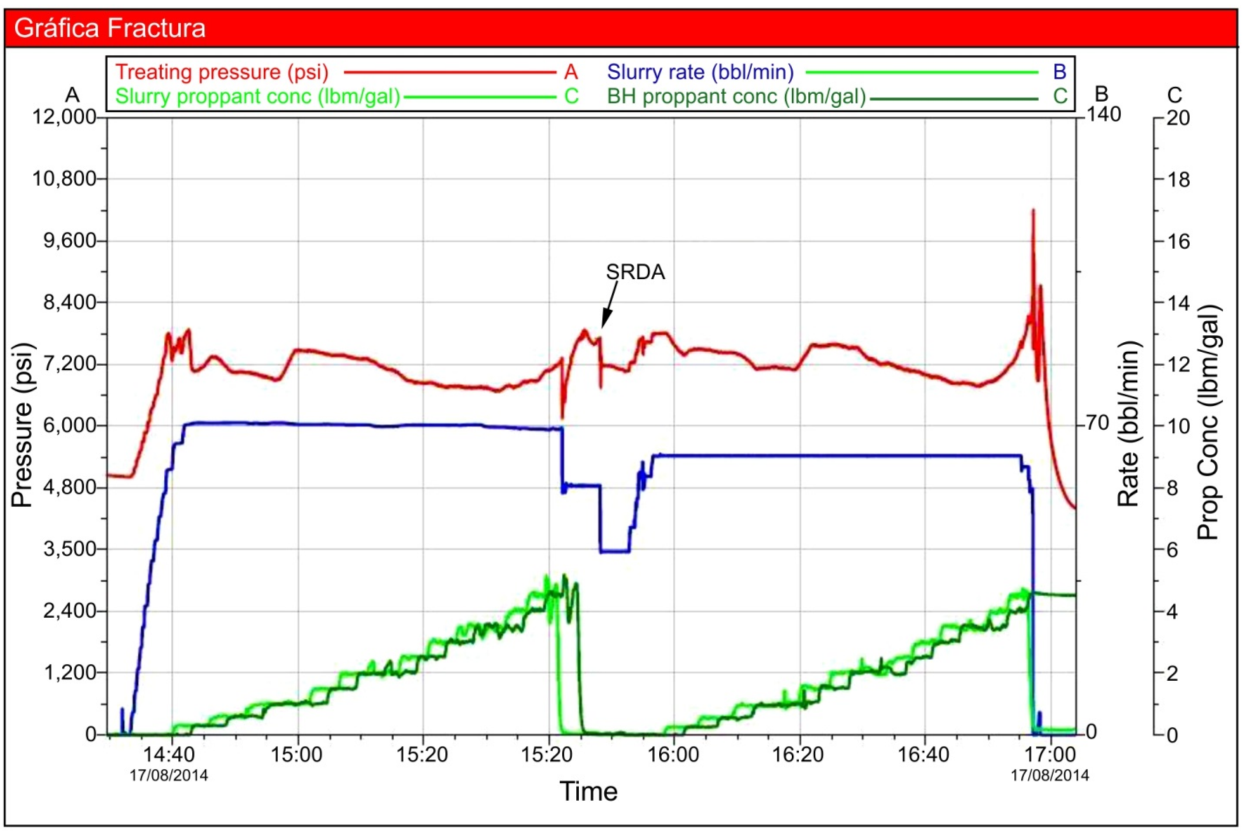


Figure 18—Candidate B multistage fracture chart.

SRDA was pumped after the proppant had passed the wellhead, decreasing the rate to 40 bbl/min to seat the diverter. Figure 19 focuses on the diversion stage and shows the results obtained.

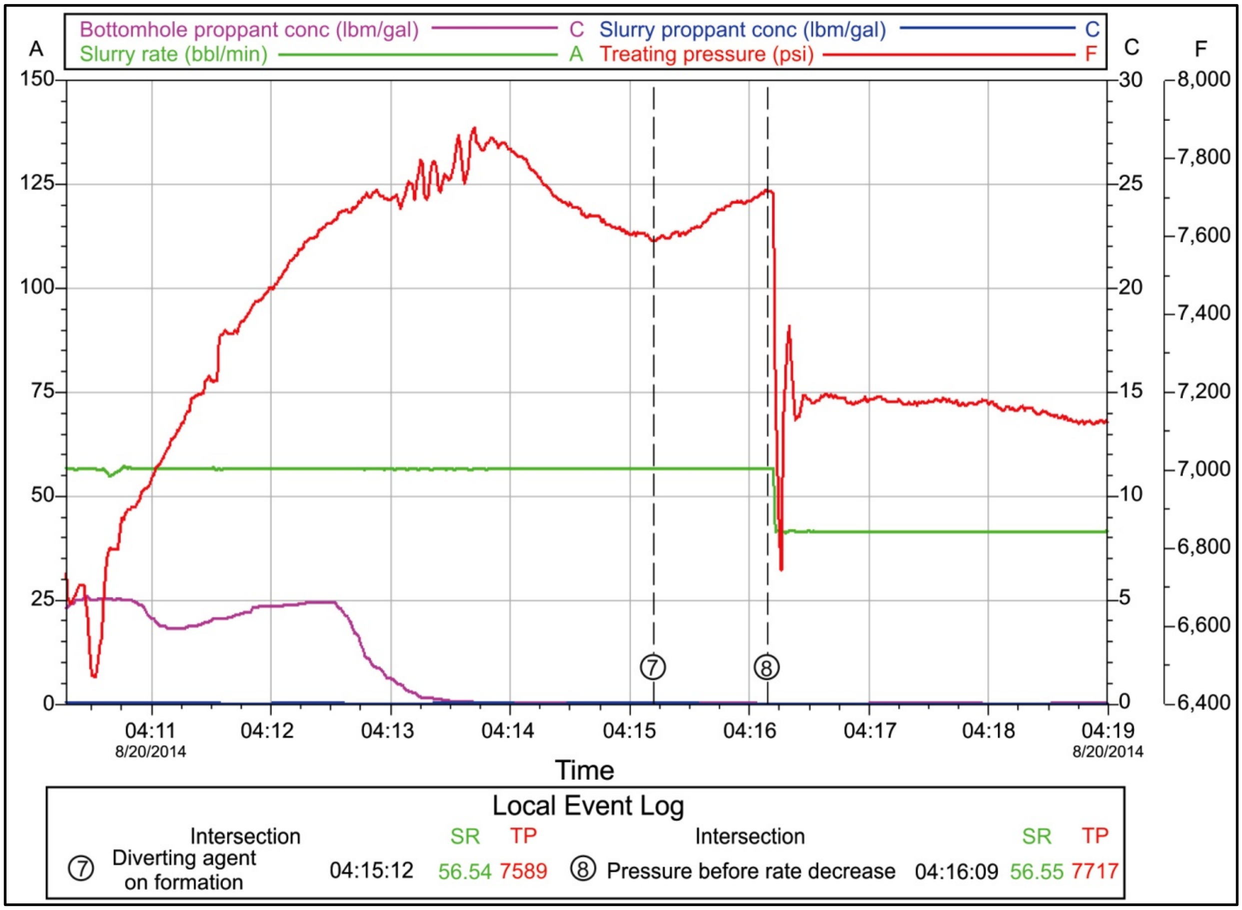


Figure 19—Pressure response to SRDA treatment.

A pressure increase of 128 psi was measured, so the rate was reduced even though the pressure was still rising. Nevertheless, this did not have a negative impact on diversion. Whether the rate was reduced while pressure was still rising, factors other than pressure increments need to be considered to evaluate if diversion was achieved. Consequently, both treatments were plotted together so pressure trends between stages could be compared.

The turquoise line in Figure 20 is the treating pressure for Stage 2. The treating pressure was higher for Stage 2 at a lower rate. The average treating pressure and rate for Stage 1 was 7,136 psi and 70 bbl/min, respectively. Stage 2 had an average treating pressure and rate of 7,290 psi and 63 bbl/min, respectively. This increased pressure resulted from a decrease in perforations and/or fracturing a higher-stressed zone. Both prove that diversion occurred. The pressure trends also appear to be different, implying that different zones or perforations were stimulated. The stimulation treatment did screen out prematurely.

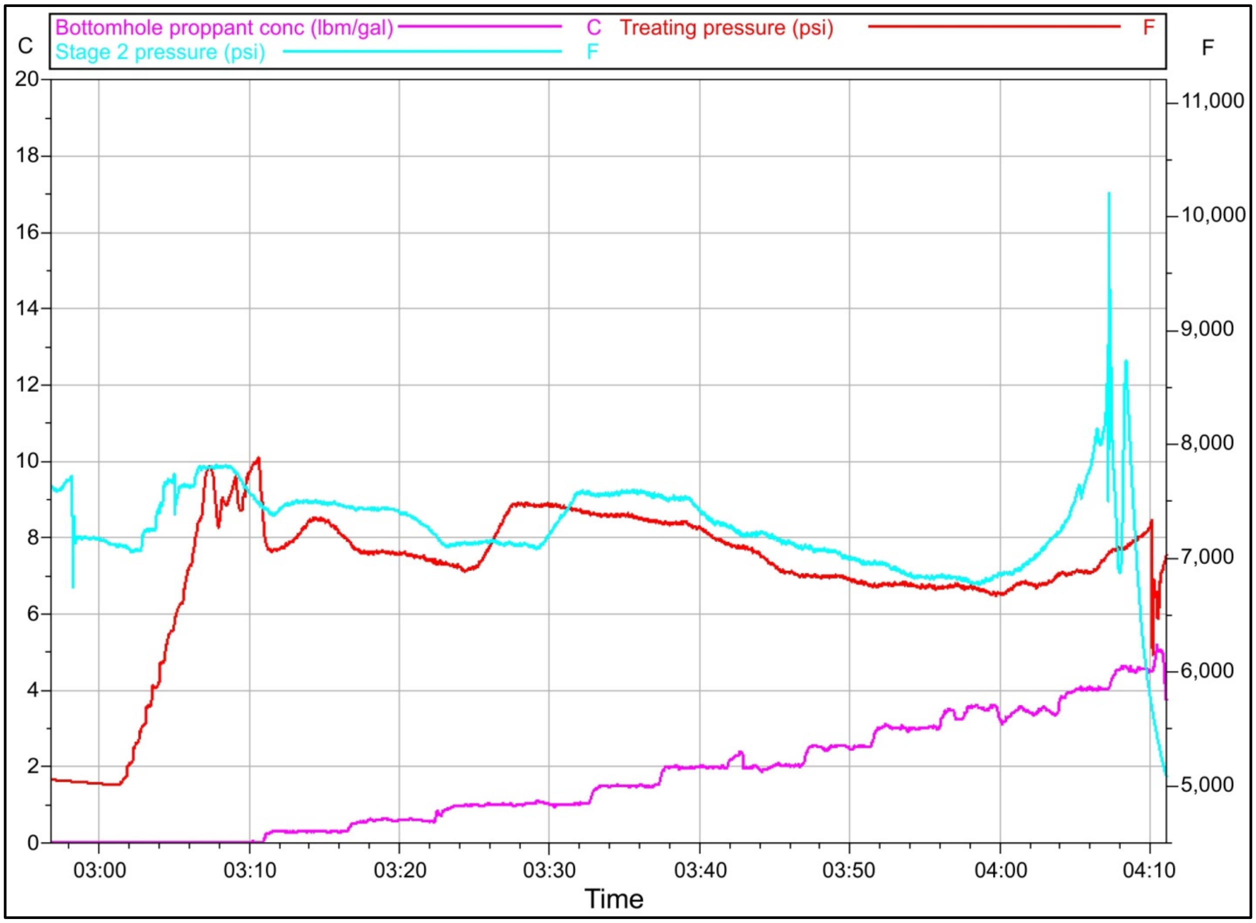


Figure 20—Overlapping treating pressure Stages 1(red) and 2 (turquoise).

Indications, such as different pressure trends and incremental average pressure at lower rates, are evidence that diversion was achieved. Premature screenout limited the application of a second reduction to compare and extend this analysis.

Production Rates/Volumes

Following the original completion, candidate Well A was flowed back and rates were 19,080 m^3/D of gas, 98.64 m^3/D of oil, and 79.6 m^3/D of water at 4,600 psi [wellhead flowing pressure (WHFP)]. Production declined quickly, GOR increased, and after two years, there was no pressure to move reservoir liquids to surface. Some production was maintained by cycling, opening once a month for a few days until the pressure fell below the producible range.

Days after the SRDA refracturing treatment, the well was opened, and the WHFP was 3,500 psi. The initial liquid flow rate was 72 m^3/D of 100% flowback water. The first oil manifestations appeared 7 hours later. After 285 hours of producing, 16% of the fracturing fluid had been recovered. Flowing pressure at this time was measured at 2,290 psi. Compared to the original response, the pressure behavior was slightly different for the same production period, but a less aggressive decline curve was observed (Figure 21). The initial oil production post-refracture was approximately 50% of the initial production from the original completion, and gas was just under 40% (Figure 21).

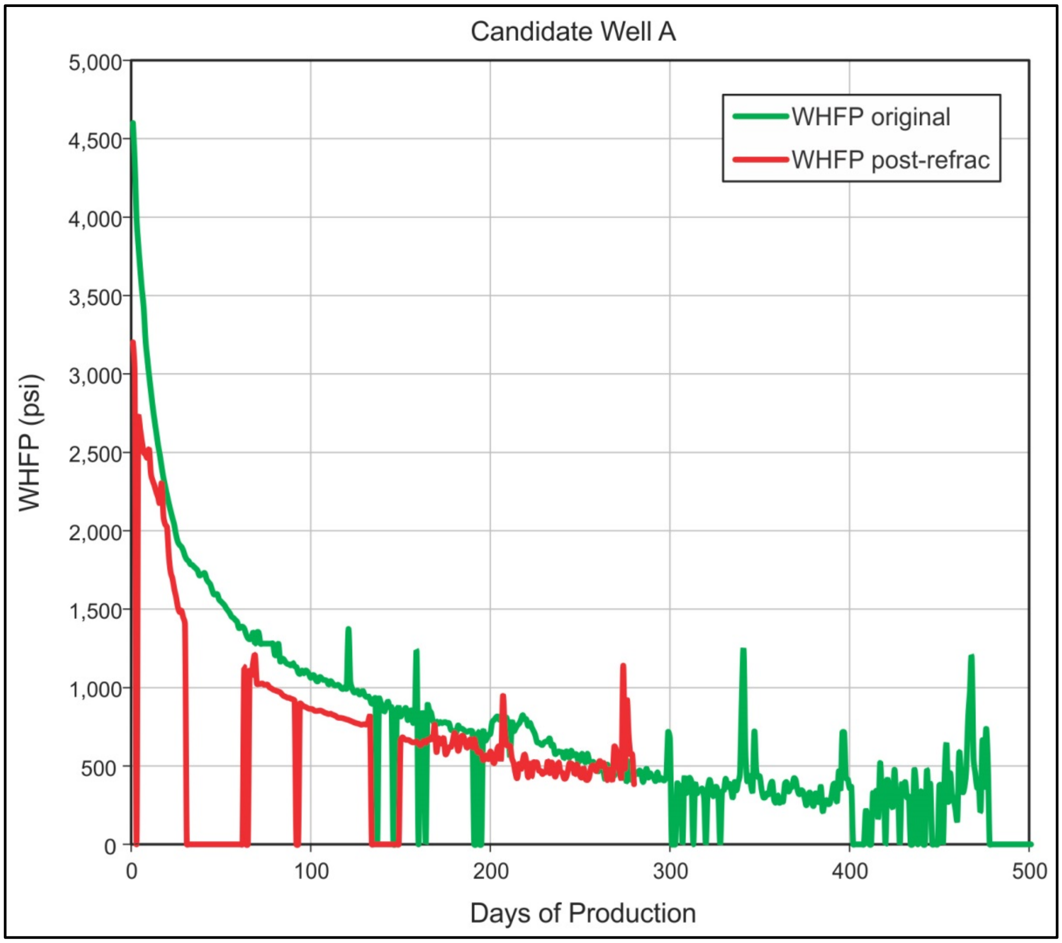


Figure 21—WHFP following the original completion compared to the pressure after the refracture treatment.

A production logging tool (PLT) was run after 9 months of production to verify the production source. The log could not be run to the bottom of the well because of proppant accumulation. The well was cleaned after the recompletion, reaching TD, so proppant flowback issues were evident.

In regards to the temperature log, a cooling effect was noticeable above 2862/2863 m (9,390/9,393.5 ft). This is likely the result of gas production over this zone. Below 2910 m (9,548 ft), the PLT registered a deviation from the geothermal gradient, decreasing temperature as a result of liquid and gas (bubble) production from below. Therefore, fluid was likely moving through the proppant pillar (clusters between 9,625 and 9,727 ft).

Capacitance indicated a water presence through the entire column, while the density log (between 0.81 and 1.1 gr/cm^3) indicated the presence of gas, oil, and water. The pressure log did not indicate abrupt changes that could help identify levels or differences between interfaces.

Figure 22 shows the results for density, temperature, capacitance, and fluid speed. Interpretation of these establishes the trend for an understanding of production provenance. The blue, green, and red bars are an indication of the total rate for water, oil, and gas (respectively) under standard conditions.

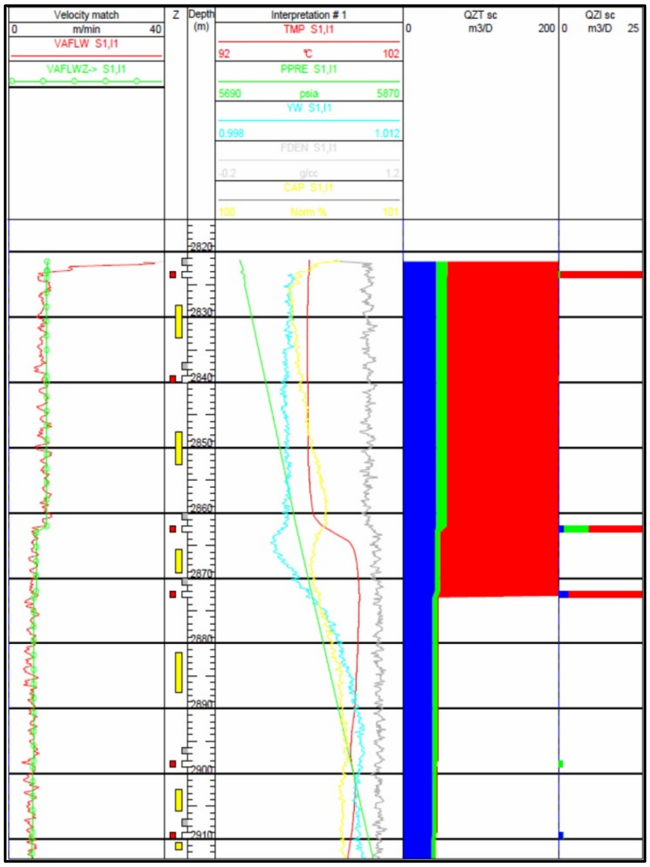


Figure 22—Post-refracture PLT.

The multiple proveniences of gas and liquids indicate that multiple clusters in the interval were stimulated through the use of the SRDA.

The well is on continuous production 1.5 years after restimulation, having added more than 20,000 bbl of oil. EUR for this well also improved, adding 10 years of additional reserves (Figure 23).

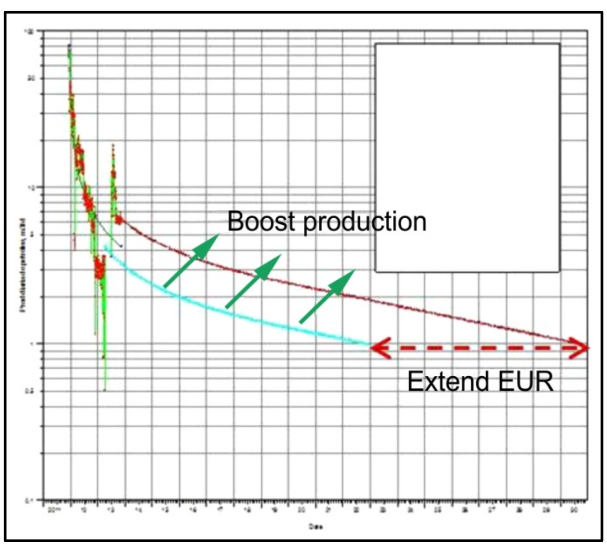


Figure 23—Decline curve analysis from achieved results.

Restimulation, then, is a feasible operation to both boost production and extend reserves.

Candidate Well B

As previously mentioned, this well included an added zone for restimulation between clusters, as well as two new plug-and-perf zones.

Once the well was opened for production, the gas flow rate was incrementally increased by 80% compared to the original treatment. The PLT showed 73% of the total flow coming from the refractured zone, while the new zones were producing the remaining 27%. This information could foster many discussions on the sweetspot location for Vaca Muerta.

Additionally, considering only the refractured zone, the new perforation actually has the most production. This implies the restimulation was able to break down that zone, where it was expected to be harder for the fluid to enter. Note that the remaining clusters were already opened at the original stimulation. This, considered jointly with the pressure trend analysis, indicates that fluid entered these zones and then diverted into the harder rock.

Economic Value Created

Treatments were pumped to completion without interruption, without wellbore interventions, with no plugs to remove, and no additional operational steps necessary for removing the SRDA. Additionally, the well was able to be brought back online quickly.

The reservoir responded favorably to incremental increases in production rates, potentially extending the well’s economic life. This will be confirmed over time and with review, maintaining the possibility that refracturing is not adding reserves but accelerating reservoir drainage.

Reservoir response and completion efficiency produced a favorable outcome for the Vaca Muerta development.

CONCLUSIONS

The Vaca Muerta holds vast potential as an emerging international shale play. With significant advancements occurring since its initial development, wells that were completed early are potential refracturing candidates for which evolved stimulation designs and techniques can be applied. Production response in the Vaca Muerta formation was favorable to the application of the hybrid fracturing design, evidenced by a more-stable production decline than was observed following the original completion.

Most unconventional multistage wells are potential restimulation candidates at some point in their life cycle. Primary candidates include those completed early in a play’s development that are deemed understimulated compared to current evolved stimulation designs and techniques. Some might be candidates because of poor cluster efficiency in the initial stimulation, resulting in ineffective stimulation of a portion of the perforation clusters in each stage interval (Ingram et al., 2014).

SRDA was observed to be a feasible and effective method to restimulate a multistage well without requiring additional wellbore interventions. SRDA also demonstrated the ability to continuously stimulate high-volume (sand and water) treatments in a short amount of time, which leads to the potential for applications in new completions and a possible improvement in the current economic state of the Vaca Muerta for the operator.

The application of this technology was successful in many aspects. Logistically, it was possible to perform a continuous operation, pumping 1.35 million lbm in 7 hours during five stages. From a technical perspective, effective diversion can be inferred when even opening new zones, by multizone production from the PLT run, by surface pressure responses following each diversion, average treatment pressure differences, and the favorable and stable production response.

Results presented in this work from the first multistage continuous pumping operations using a SRDA in the Vaca Muerta formation provide insight for the development of unconventional reservoirs in Argentina, potentially enabling methods to evaluate future multicluster completions and identifying refracturing candidates.

ACKNOWLEDGEMENTS

The authors thank YPF and Halliburton management for permission to publish this work.

NOMENCLATURE

BHST = *Bottomhole static temperature*

BHTP = *Bottomhole treating pressure*

BOE = *Barrel of oil equivalent*

EUR = *Estimated ultimate recovery*

HHP = *Hydraulic horsepower*

m^3 = *Cubic meters*

PLT = *Production logging tool*

SRDA = *Self-removing diverter application*

Tcf = *Trillon cubic feet*

TD = *Total depth*

TOC = *Total organic carbon*

TVD = *True vertical depth*

WHFP = *Wellhead flowing pressure*

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