Volver

Annular Fracking, A Case Study Of 4 Vertical Multistage Wells In The Lajas Tight Gas Field

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The Lajas tight gas formation lies in the Neuquén Basin, located in the province of Neuquén, Argentina. The Lajas formation consists of more than 800 m of sandstone, heterolithic (interlaminated mudstones and sandstones), and mudstone deposits accumulated in different marginal marine setting.

Vertical wells have been drilled and completed since the early phases of exploration and development of the field. Typical completions have called for using the Plug & Perf stimulation technique. This method of completion is not a true continuous operation method and obliges the operator to make multiple operational stoppages. In order to remain economical and avoid stimulating the individual clusters one after another, the plug and perf method forces a combination of intervals to be stimulated simultaneously. If the targeted zones have varying widths such as in the Lajas field this method does not allow for a customization of the design for each targeted entry point based on width of the target zone or its quality.

In the search for uninterruptedness of operations and the ability to customize each lenses' fracture design, the operator started considering other options for stimulating the wells in Lajas. Annular fracturing with packer isolation was considered as the proper way to allow both effective individual stimulation of clusters and customization of design. While annular fracturing has expanded significantly in North America in the last few years it has for the most part been applied in horizontal wells. Many challenges associated with its application in vertical wells had to be accounted for which were perhaps not necessarily considered in horizontal well designs.

This paper discusses the application of annular fracturing in the Lajas field and its successful operational implementation in four wells. Well construction, technical challenges including coiled tubing and fracture design techniques had to be considered to make this completion successful. The operator has observed a significant cost reduction and operational efficiency increase as a result of this technique.

Vertical Vs Horizontal, Formation width

The principal difference between a horizontal reservoir stimulation and a vertical one is target location. In a horizontal well the drilling is thought, for the most part to be targeting a homogenous section of a reservoir by not deviating from a set trajectory. This trajectory is controlled with the use of directional drilling, a technique widely used in today's unconventional stimulations. In a vertical well however, the reservoir's natural boundaries force operators to ensure that the perforation location is exact. This is even more so if the zones to be stimulated are thin and do not have natural height boundaries that permit errors in location.

In the Lajas tight gas field the zones stimulated amount to around 16-20 in each well. In each well the formation is categorize into three different sections, Lajas inferior, Lajas intermediate and Lajas superior. The inferior portion of Lajas holds a wider section of reservoir which allows for ample placement for target location. The intermediate and upper sections however are mainly constituted of 3-5 meter sections of varying permeability and porosity which must be stimulated if the well is to be economical. Some of the target zones are as thin as 2 meters. Examples of the distribution layers is in figure 1 below which shows the associated widths of each zone targeted for stimulation.

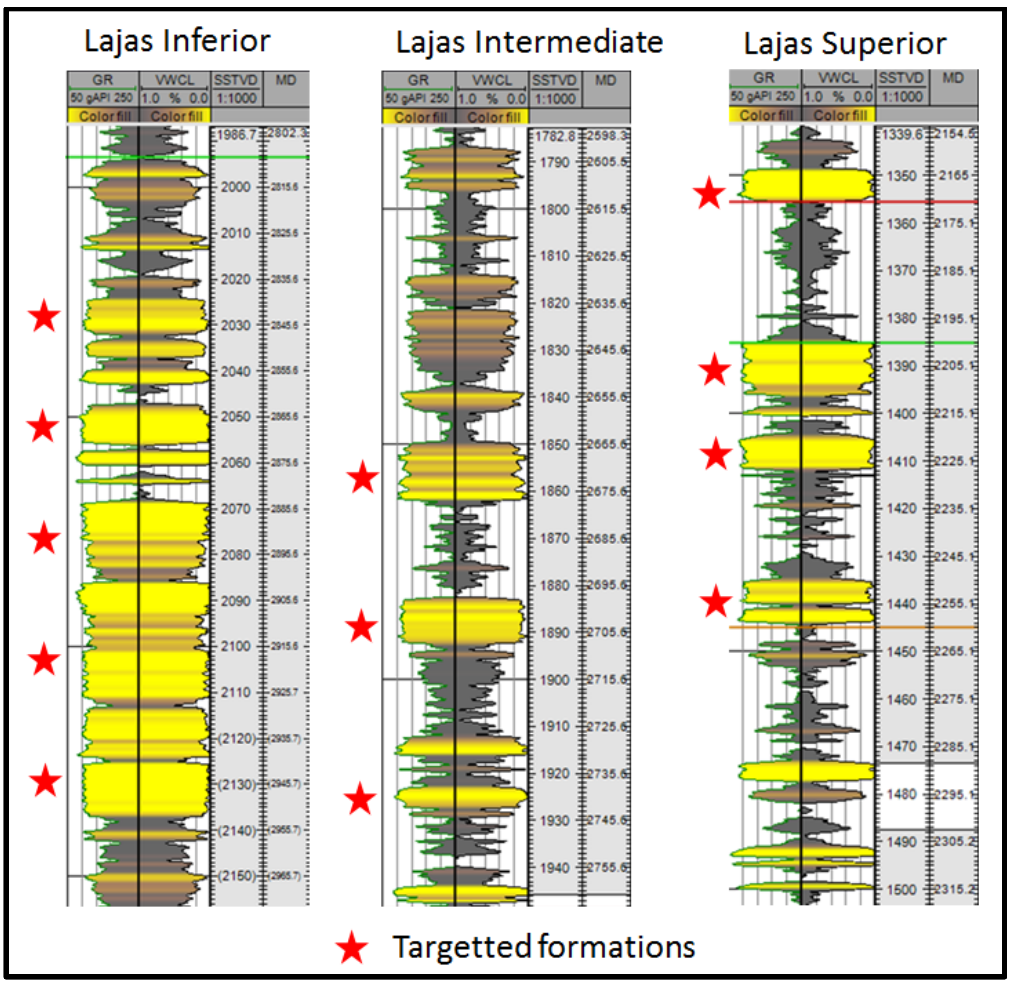

Figure 1 - Lajas Reservoir Sections

Why Annular Fracking?

The current stimulation technique in Lajas is called Plug and Perf. This technique is based on the principle of differential pressure generated by an increased rate and impacted by a reduction of perforations in number and size in the stimulation phase. In theory, it allows for multiple targets to be stimulated simultaneously. A perforating gun is lowered with a wire line and the wire length is used to determine the exact location to perforate. Prior to perforating, locations have to be identified using an open-hole log analysis. This analysis allows for exact determination of the targeted formation. After the perforation process, the wireline is removed from the well and the stimulation process (fracking) can begin. Once the stimulation finished a plug has to be lowered to isolate the next treatment from the previously stimulated interval or the proppant ladden fluid will not be fully placed in the target formation, potentially negatively impacting the production of this interval. This process is repeated until the well is completed and all of the zones have been stimulated. Following the stimulation the plugs have to be drilled out because they prohibit the pathway for production. Each of these steps requires time and certain changes in operations which in turn translate to more time loss on location.

In today's cost mindful environment a technique allowing for uninterruptedness is necessary to minimize time on location and for the projects to be economical. Annular fracking is one such solution however it requires certain know-how to ensure a proper implementation and an operational success in the field. The process of annular fracking is basically one where a tool is lowered at the bottom of coiled tubing (flexible metal pipe) and this coil is lowered into the well. The tool allows for abrasive jetting and for zonal isolation simultaneously, providing the ability for continuous stimulations until all targets are successfully stimulated. Figure 2 shows the tool which was employed in the Lajas stimulation of the 4 wells.

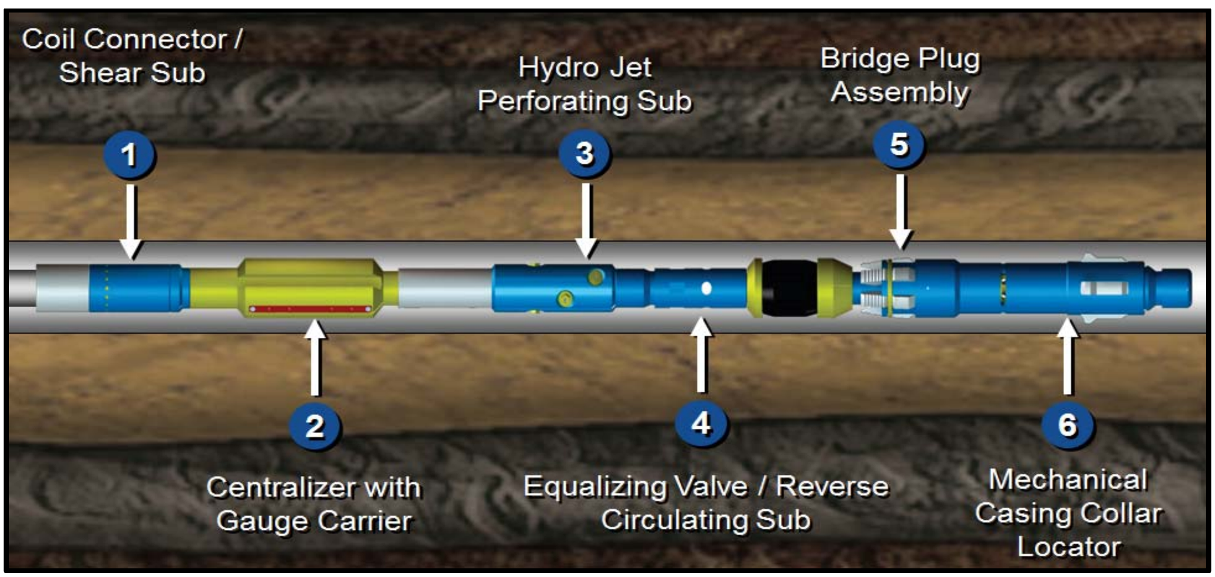

Figure 2 - Annular Fracking BHA

Annular Fracking, Depth Correlation

One of the main challenges of annular fracking (without the use of sleeves) is depth location. Referring to previously stated differences between horizontal and vertical, in a horizontal well the reservoir is assumed to be homogeneous and depth location is lesser of a concern. In a vertical well however, depth location can be the difference between a successful and an uneconomical project. Today's Coiled tubing is estimated to have about ~1m error for every 1,000 m however this value can sometimes be greater depending on the measurement means and equipment utilized. In Lajas the target depth can reach 3,000 m and at that depth the error from surface could translate into +/- 3 m up or down for the targeted depth. To avoid this situation a mechanical collar locator (referred to as the MCCL) is employed to determine passage of the tool between collars. This section of the tool can be observed below in figure 3.

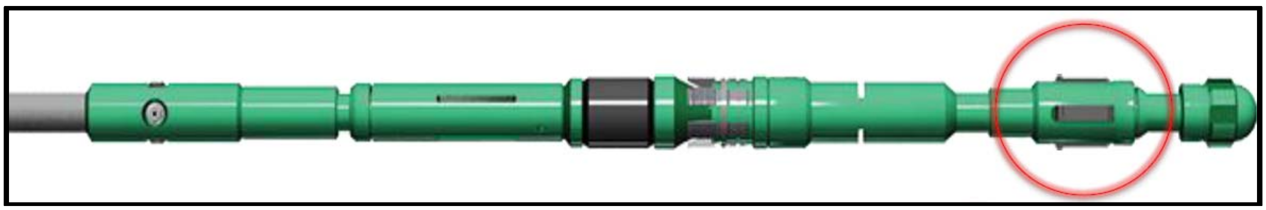

Figure 3 - MCCL on BHA

The challenge is to determine if the producer employs casing joints with a buttress type connections or another type without a deviation which may not allow a for the true depth determination. In the case of a connection with an angle or bent in between the joints (typically buttress) the MCCL can be used to determine the location of the tool. Since most of the casing joints used by the oil and gas operators in Argentina are longer than 9 m once a passage by a collar has been identified the depth can be estimated with great accuracy. Figure 4 shows an example of one such collar connection with a bent which allows the MCCL to locate the depth of the tool.

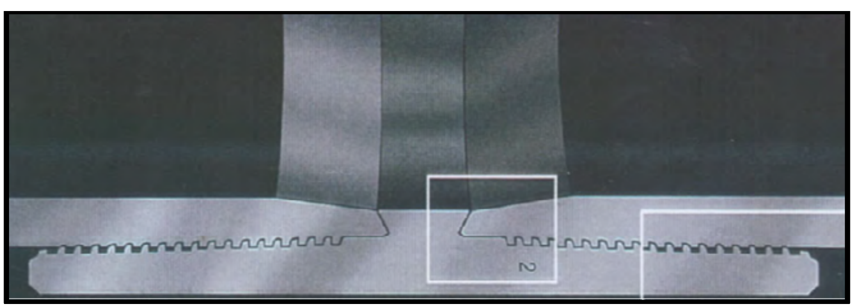

Figure 4 - Example of Collar with Bent

In Lajas the well design does call for this type of connection so other precautions had to be taken to ensure proper depth correlation. The service company proposed to lower a plug below the perforations to use as a reference and to be able to re-set depth location much closer to the formations targeted rather than doing it from surface. This process meant that as the tool was moving away the error of the tool depth was growing. The maximum depth error was determined by the maximum distance between the lowest formation and the highest one. In the case of the first stimulated well in

Lajas that error was estimated to be a maximum of 1 m since the distance between the deepest and shallowest formation was approximately 1000 m.

The plug allowed for proper depth correlation, however this was only valid so long as the tool did not have to pull out of hole (POOH). If a trip had to be made to change any part of the tool another plug would have to be lowered to ensure that proper depth correlation is maintained. This was especially critical because the tool could not be lowered below past previously stimulated zones since that risked damaging its rubber packer and would no longer guarantee its integrity.

Abrasive Jetting, Challenges and Solutions

In the first Lajas well such a trip was estimated to be necessary in the middle of the operation because of the erosion created around the jets. This erosion is the result of what is known as the "Splashback". It is hard to predict and is dependent on many factors such as rate, proppant used, annular space distance between the jets and the tool etc…

In the first Lajas well the tool was pulled out of hole after the first 10 zones were stimulated. The jets were severely eroded and had to be changed for the operation to continue. Figure 5 shows the extent of the erosion of the jets.

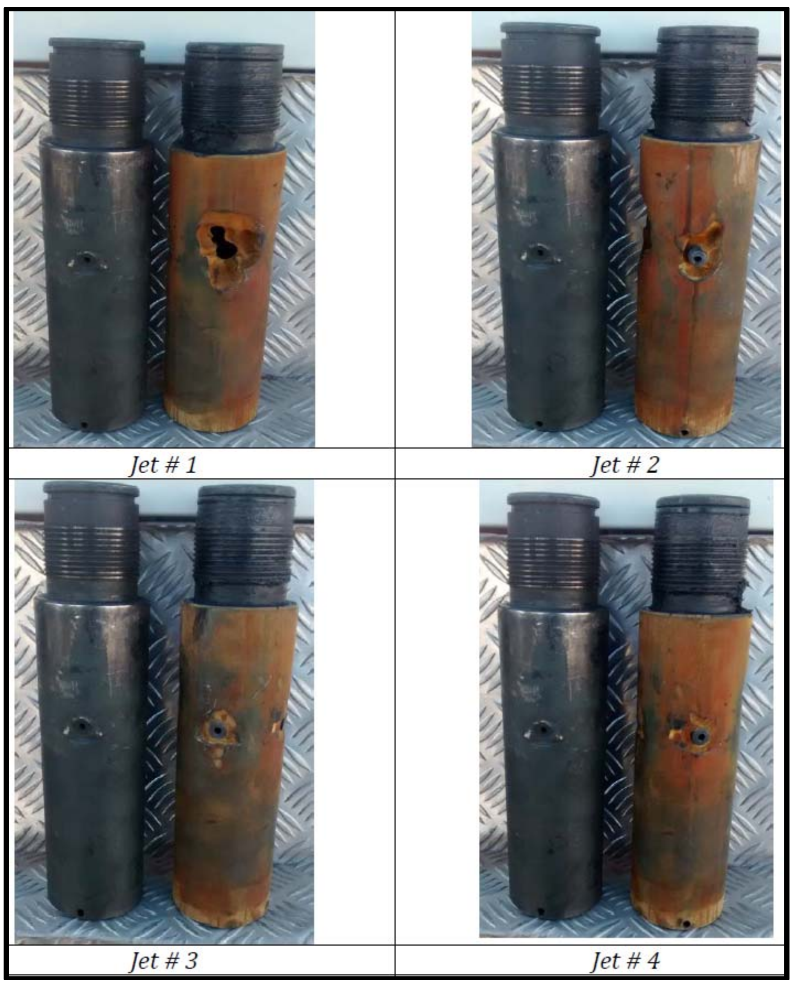

Figure 5 - Jet Erosion (Actual Vs New)

It was determined that this was an issue that needed to be dealt with and a re-enforced jet design was called for. The service company introduced a re-enforced design Jet and ensured to have it present for future wells. The more robust design had a tungsten carbide protection layer around the jets which allows for much higher resistance to the splash-back effect of the abrasive jetting process

Depth Correlation Verification

Following the fracturing operation in the first well the operator lowered a multifinger tool to determine the exact location of the abrasive jetting versus what was estimated with the coiled tubing. The error was mostly within the predicted range. Even though the separation was a little more than initially estimated all of the cuts were within the target zones and that portion of the operation was deemed a success. Figure 6 shows a table with the difference in depth located with the multifinger tool. Figure 7 is a 3D interpretation of the Multifinger.

Jet Perf Realizado (m)	Jet Perf Programado (m)	Lectura Multifinger (m)	Diferencia Real Vs Multifinger (m)	Stage
2990.0	2990.0	2990.3	**0.3**	1
2937.0	**2942.0**	2936.8	**-0.2**	2
2921.0	**2918.0**	2922.0	**1.0**	3
2890.0	2890.0	2890.4	**0.4**	4
2868.0	2868.0	2869.2	**1.2**	5
2845.0	2845.0	2846.8	**1.8**	6
2740.0	2740.0	2741.3	**1.3**	7
2705.0	2705.0	2706.1	**1.1**	8
2670.0	2670.0	2671.6	**1.6**	9
2655.0	2655.0	2657.2	**2.2**	10
2674.6	Tapón			
2555.0	**2554.0**	2554.8	**-0.2**	11
2535.0	2535.0	2535.3	**0.3**	12
2505.0	2505.0	2506.3	**1.3**	13
2489.0	2489.0	2491.3	**2.3**	14
2416.0	2416.0	2418.2	**2.2**	15
2355.0	2355.0	2352.7	**-2.3**	16
2252.0	2252.0	2254.8	**2.8**	17
2224.0	2224.0	2225.4	**1.4**	18
2205.0	2205.0	2206.8	**1.8**	19

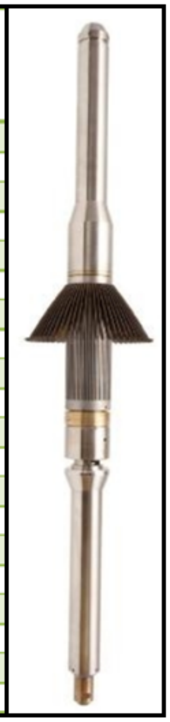

Figure 6 – Real Vs Programmed Depths

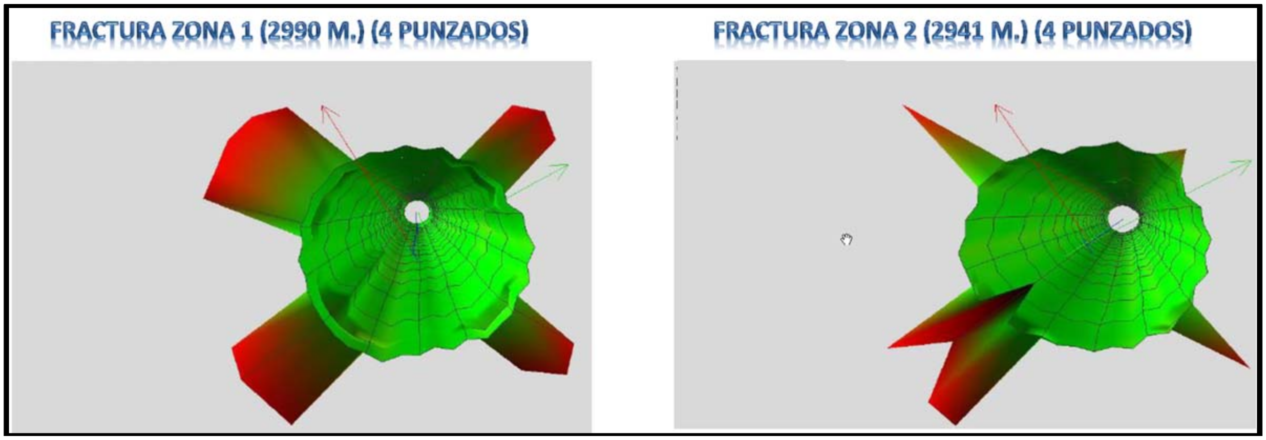

Figure 7 - Multifinger 3D (Zones 1 & 2)

Well Design Challenges

The second well's design was different from the typical designs for the area. The wellbore had an open bore hole of 8 ¾" with a 4.5" casing lowered into it for drilling reasons. Typical well design in the area has $6^{1/8}$" bore holes where 4.5" outside diameter casing is lowered. The second well design meant that there would be much more cement present thus separating the frac fluid from the formation to be broken down. This situation created a challenge for abrasive jetting since the process was not known to have deep penetration even though 15% hydrochloric acid was utilized to aid in the breakdown process. Typical abrasive jetting penetration is known to be wider but not deeper than conventional explosive perforations. One possible solution was to introduce nitrogen into the abrasive jetting process to obtain deeper penetration but that was not a recommended or typical practice since there is too much friction associated with the use of nitrogen down the coiled tubing. Figure 8 below show examples of abrasive jetting penetrations in real life and in theory.

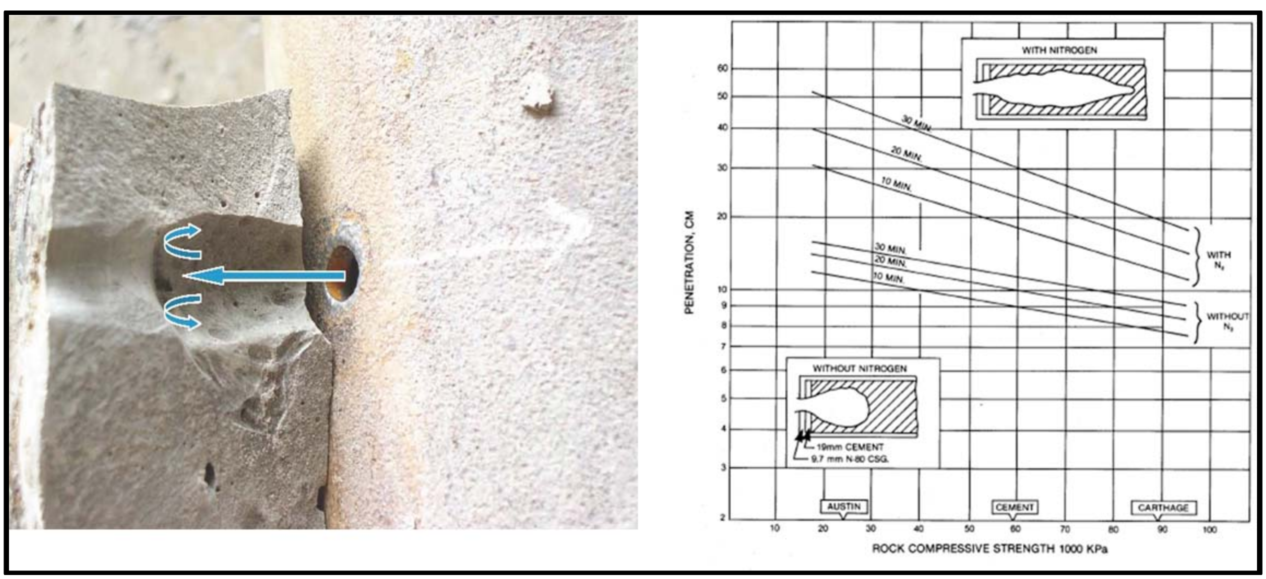

Figure 8 - Abr. Jetting (Real Vs Theory)

There were multiple issues related to cutting on the second well, the tool's abrasive jetting section had to be replaced 3 times during the operation. The cuts with abrasive jetting were required to be done using double the normal allocated time and about double the volume of acid was used. In the end all of the targeted zones were stimulated successfully.

<u>Abrasive Jetting – Improved BHA</u>

By the third well the tool had gone through a significant change and the new jetting apparatus was provided. This apparatus was estimated to allow for up to 10 times the typical longevity of the jetting tool. Both this well and the next (4^{th}) were performed without changing the BHA and allowing for the entirety of the zones to be stimulated without removing the BHA. Figure 9 shows the impact on the new apparatus after the entire 3^{rd} Lajas well was stimulated with 16 zones.

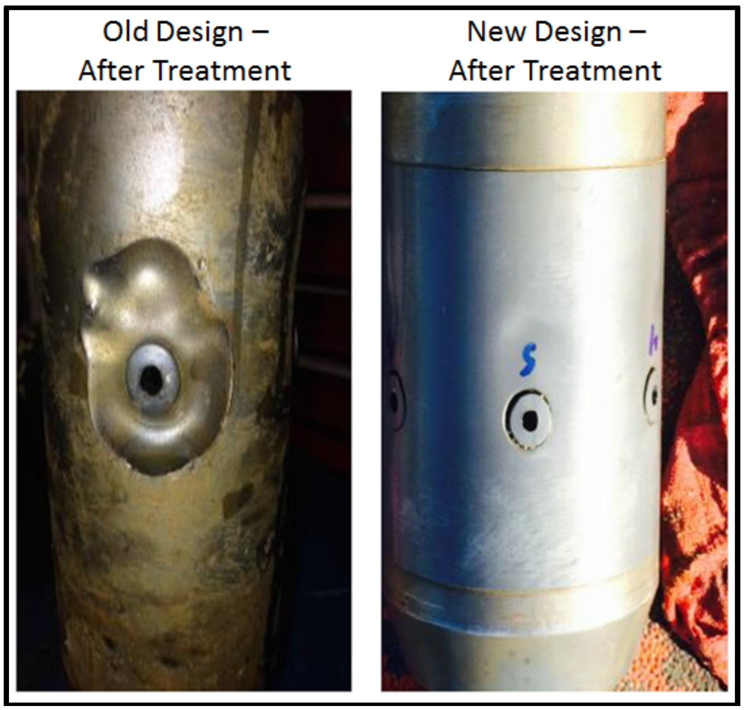

Figure 9 - Improved BHA for Jetting

<u>Annular Fracking – Fluid Friction</u>

Fluid Friction was also an important factor in these operations. Since the casing was L-80 its 80% threshold from maximum pressure did not allow sufficient operating "room" to operate for cases of screen-out. An additional 2,000 psi back pressure between the intermediate casing and the lower casing was necessary to ensure proper room. One of the concerns is that for the additional pressure to be valid or holding during the operation the top of the cement had to have reached deep (minimum 50 m) into the space between the two casing joints (intermediate and production casing). This was not the case in the second well and measures in the field had to be taken to ensure that the maximum pressure would not be exceeded in the first frac.

The additional back pressure was not a sufficient solution to alleviate the effects of crosslinked fluid friction. This was because pressure behavior in annular space was non-linearly incremented compared to conventional fluid friction. The stimulating rate was at a maximum allowed (35 bbl/min) and a management of change had to be requested to exceed the standard 35 ft/sec velocity threshold.

Complete friction typically consists of 3 elements: Fluid friction, perforation friction and tortuosity friction. Since the abrasive jetting process left holes with diameters wider than conventional explosive friction. This removed the concern from perforation friction.

The abrasive jetting apparatus consists of 4 holes which are all on the same angle and since the optimum phasing in perforation philosophy calls for higher then 60 degrees phasing the tortuosity was not thought to be a concern with the annular fracking technique (90 versus 60).

Having covered two out of three we were left with the fluid friction challenge. In order to resolve the issue related to the fluid friction a delayed crosslinker was used to reduce a maximum possible the friction effects of the fluid. The fluid system was still borate based and the activation time was made to have final viscosity at about 75% of the fluid travel time at programmed rates. In addition to this some small concentrations of friction reducer were added to allow even further reduction of fluid friction.

<u>Annular Fracking - Operational Efficiency & Costs Savings</u>

The first well took 3 days and 29.7 operational hours. By the time the 4th well came around the entire operation came down to 31 hours total of which around 22 were operational. The real target was to get under 24 hours and was totally feasible after an analysis of non-productive times (NPT). Essentially all of the services were geared towards non-stop operations and they to that was uninterrupted logistics. One of the requirements for these operations is to have all of the sand and water necessary on location to be able to continue until the entire well was stimulated.

An in-depth analysis was also performed to estimate the cost benefits of such a technique. Since there was no need for wireline and plugs that cost was removed. The use of annular fracking and Ct reduced the fluid volume necessary by about 15% compared to conventional operations. There was an increase in Coiled Tubing costs due to the service of annular fracking and use of Coiled Tubing. This was however more than compensated with the reduction of time spent on location with the new technique (a >50% reduction). Overall the costs savings were thought to be around 25% for the entire operation as can be observed in figure 10 below.

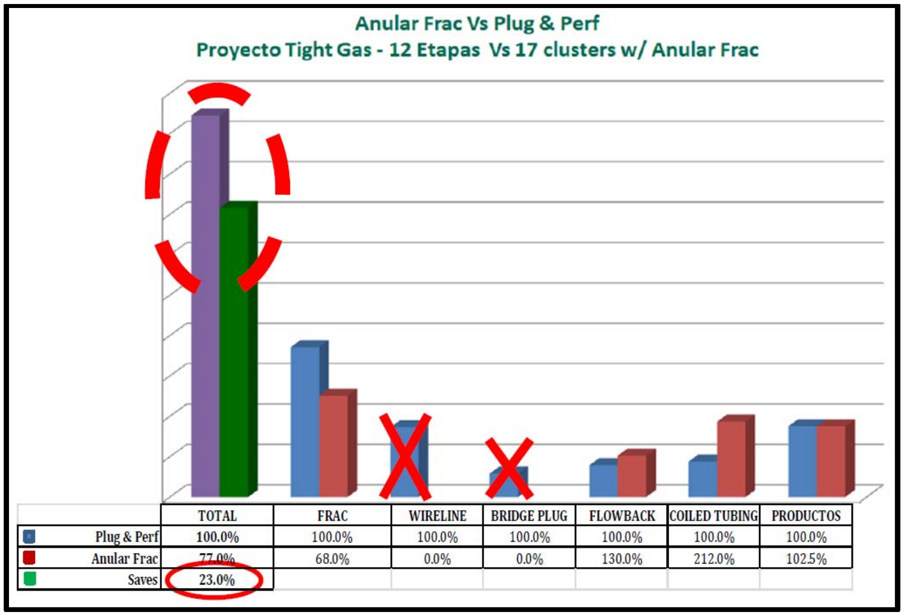

Figure 10 - Costs Savings Analysis

These were all costs related to the service company charges but there were other cost reductions as well for the operator. If the services contracted by that operator were spending 50% less time on location that would allow for a reduction on his other services costs (examples include tree saver, rentals ect).

A typical well after a plug and perf operation had to have the plugs milled and this added 2-3 days. Utilizing annular fracking, this would not be necessary as the well would be readily available for clean up as soon as the stimulation was finished. In the end an operator could have it well ready to be put on production about 6-8 days sooner than a conventional operation which translated in a tremendous efficiency improvement.

Conclusions

1. Annular fracking is much more challenging in vertical wells then it is in horizontal wells
2. Annular fracking BHA can reduce complexity of operation and permits performing an entire operation without interruptions
3. Well design plays a big role in the success of the operation in annular fracking and sets the limitations in terms of rates and pressures
4. Annular fracking can lead to up to 50% less time spent on a well for completions operations
5. Annular fracking can reduce up to 25% compared to conventional costs
6. Annular fracking presents a viable and cost effective completion method to replace conventional plug and perf operations