RIGLESS CEMENTING TECHNIQUE TO SHUT OFF BOTTOM INJECTION AND PRODUCTION

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SUMMARY

Injection and production below the OWC and in thief zones are common problems in many carbonate reservoirs. Conventional methods to remediate water injection thief zones are expensive, largely due to well control costs. A method to repair bottom water injection with reduced or eliminated rig costs is presented, along with lessons learned from successes and failures utilizing this methodology. Specialized cements and techniques have been investigated to help ensure the needed capabilities and attributes for near wellbore repair as well as extensions into channels, fractures, and high permeability streaks. In addition to the injection well work, successful examples utilizing a similar procedure on producing wells are presented.

APPLICATION BACKGROUND

Permian Basin San Andres and Grayburg carbonate reservoirs developed in a shallow ramp environment, with stacked pay zones (along with minor cycles within each pay zone) generally grading from supratidal to subtidal deposition moving down within each zone. The lower zones generally have higher permeability and in some cases have a shallower oil-water contact (OWC) than the upper zones. In some cases, the zones have a very poor seal dividing them – basically a low vertical permeability layer with little structural strength. The majority of the reservoir rock in these reservoirs is less than 10 MD permeability, and stimulation (fracturing) is required to develop an economic well. As a result, many wells have induced fracture communication below the OWC in spite of a total depth at or above the OWC. In addition, natural fractures, directional permeability and channels are often encountered in these reservoirs. Because of this geologic setting, production and injection below acceptable oil saturation has been a frequent problem in these carbonate reservoirs.

A large percentage of Oxy's wells are open hole completions, with 100-300 feet of gross pay encompassing 2-5 producing intervals. Over the past several years, highly successful procedures have been developed to address production below the OWC. The most successful procedure is squeezing cement under an open hole cement retainer (suicide squeeze), followed up by perforating and acidizing above the retainer to clean up any cement damage. Total cost for this procedure on a producer is around $70,000 per well. The limitation on this procedure is the capability of an open hole retainer, which can only expand to 5" within the originally drilled 4-3/4" open hole. While a number of producing well procedures of this type have been performed, an injection well where this procedure is possible has not yet been identified, primarily due to large hole size from dissolution of rock and the numerous acid jobs that have been performed on these older wellbores. A second procedure, when hole diameter does not permit setting an open hole retainer, is to set a cement retainer in the casing above the open hole, squeeze off the completion with cement, then drill out, perforate the open hole, and re-stimulate. On producing wells, this procedure costs around $100,000. A conservative cost estimate for this type of procedure on an injection well is $150,000 due to well control costs and difficulties in drilling out the cement squeeze due to poor casing condition below the injection packer. For these reasons, injection well conformance procedures have been historically performed in conjunction with casing repair or liner installations, where the incremental cost was "relatively" low.

TECHNIQUE DEVELOPMENT

The rigless cementing technique was developed to economically remediate problems with injection at/below TD. Initial candidates had almost 100% injection out the bottom, so the downside risk of unsuccessful jobs was judged to be minimal. If the job was unsuccessful and resulted in a higher than desired Plug Back Total Depth (PBTD), the rigless job would, in effect, be the first step in performing a rig job squeezing off the completion interval. The generalized technique involves:

- Calculating the hole volume desired for shut-off (with excess), which determines the size of the cement pill (generally a six bbl minimum because of Halliburton's tub size dictating the minimum volume of good cement).

- Calculating displacement volume based on the desired PBTD and some estimate of displacement fluid losses above the desired PBTD.
- General job procedure is:
    - Pump the cement pill, shut down and wash up
    - Drop the foam wiper ball and pump displacement
    - WOC about two hours, then tag actual PBTD with wireline
    - Pump an additional stage if necessary, adjusting cement and displacement based on first stage results
    - Run post job injection profile
    - Possible follow up treatment perforating with a strip gun (if allowed by equipment configuration) and acid dump job to increase injection in desired intervals as necessary

Use of the foam wiper ball was taken from experience with cementing operations down drill pipe. In addition to assuring that the injection string is cleared, it is hoped that the wiper ball will also help to minimize cement sheath in the open hole above the plug back. Based on success in injection wells, the procedure was adopted for producing wells. One job was performed with MARCIT gel ahead of nitrified cement to handle a direct channel to an injection well that was in-line with the direction permeability trend. Some jobs were also performed with a pre-treatment of polycrystals followed by cement. Polycrystals were pumped ahead of the cement to minimize dilution of the cement by formation water and provide some longer term protection for the plug back. Additionally, they appear to help accelerate cement dehydration based on job pressure comparisons.

"Polycrystals" - crystallized copolymer Super Absorbent [CSA], are water-swellable (but not water-soluble), 100% crystalline synthetic polymer. They absorb hundreds of times their own weight in water ranging from 10 to 800 times based on the particular grind, carrier and present aqueous fluid, and the specific manufactured base material. CSAs currently used are sodium acrylate-based polymers, which have a three-dimensional, network-like molecular structure. The polymer chains are formed from the joining of millions of identical units of acrylic acid monomer that has been substantially neutralized with sodium hydroxide (caustic soda). Crosslinking chemicals tie the chains together to form a three-dimensional network, or 100% crosslinked system. This enables CSAs to absorb water or water-based solutions into the spaces in the molecular network, forming a gel and locking up the liquid.

The crystallized copolymers are resistant to degradation by CO_2, bacteria, and temperatures below 250°F. If the crystallized copolymer should require removal, it can be removed by reactions from bleaches or oxidizers generally placed with a coil tubing unit. Crystallized copolymers will start to hydrate after 20 minutes if in fresh water and at temperatures below 110°F. Use of produced salt brines (8.9–9.2 lb/gal) can result in a delay of around 45 minutes before the crystals hydrate; placement may be defined around this feature.

LESSONS LEARNED

Post job analysis has been very valuable in improving this procedure. As the first jobs were pumped, it became obvious that calculating the volume required for plug back is very difficult. In general, cement volumes two to four times the calculated volume have been required. This is believed to be due to near wellbore fractures and voids. Displacement volume is also very difficult to judge. As a general guideline, doubling the cement pill volume (with recommended 6 bbl minimum) and increasing the displacement volume by the percentage of injection losses above the plug back is a good starting point for the first attempt. Erring on the generous side for displacement volume will help to ensure that a rig cleanout is not necessary. Pumping additional rigless stages is much less expensive than a rig cleanout.

When the well is placed back on injection, injection pressure should be consistent with pre-job setpoints and the rate should be allowed to find its own level. After injection has stabilized, a post job injection profile is critical to evaluate successful plug back and determine if more follow-up work is required. Good communication with operations personnel is needed to avoid post job problems. One successful job was apparently broken down when injection pressure was increased by 150 psi in an attempt to re-establish the historical targeted injection rate. A profile after this pressure and rate increase indicated 45 percent injection right at the PBTD with significant separation between the injecting and shut in temperatures, indicating likely communication down to the old loss interval through induced fractures. In spite of this apparent breakdown, injection out the bottom is still less than the pre-job profile (both in percentage of injection and absolute rate measurements)

Pre-job injection profiles including a caliper are very important in job design. As mentioned above, the pre-job profile is needed to calculate cement pill and displacement volumes. Shut in cross-flow should be investigated as well. If a well has strong shut in cross-flow coming up off bottom, the chances of PBTD being higher than desired obviously increase. This does not necessarily mean that the rigless procedure should not be attempted, but the increased potential for a follow-up rig cleanout should be considered. An increase in cement pill size and the use of polycrystals should also increase the chances of success with shut in cross-flow off bottom.

Another potential problem identified through pre-job profile analysis is losses or inflow (including shut-in cross-flow) in non-pay intervals above the pay zone. The older injection wells often have one hundred feet or more of casing between the packer and the pay zone because of the historical practice of laying down a joint of tubing and moving uphole when difficulties were encountered setting the injection packer. In some cases, pipe is completely corroded and some amount of injection or shut-in cross flow is seen in these uphole intervals (generally believed to be fracture flow). In one well, an uphole zone with small injection losses was broken down during a rigless cement job by the high pressure encountered during displacement. Our reservoir engineer took the charitable stance that increased losses above the pay were actually caused by increased injection pressure. Regardless, the well was repaired by pumping polycrystals followed by a coiled tubing unit cleanout.

In the Levelland Field reservoir rock in the lower zone is very easy to fracture due to higher permeability than the upper zones. Cement pill volumes from 25 to 200 sx have been pumped. It seems as if once the cement starts into some fractures very large volumes can be pumped at will. This concept is supported by conformance work done on other wells in the field. It is likely that fractures are being extended and filled with cement in these larger volume jobs. This is not considered to necessarily be a problem as the larger cement volume may help to assure good quality cement closer to the wellbore.

The five LLU injectors were done as part of well work for the phase two CO_2 flood. All of these wells (except LLU 274) were scheduled for a rig job to replace downhole injection equipment; therefore the rigless jobs were designed with aggressive cement volumes because incremental costs to drill out a higher than desired PBTD were minor. It would appear that the polycrystal lead stage has a significant effect in accelerating cement set time, as both jobs using polycrystals (243 and 272) locked up and tagged high after only one 6 bbl stage. Wells 511 and 554 had two 50 sx stages pumped and both required a rig drill out. Had these wells not been scheduled for pulling, a smaller second stage with more displacement volume would have been pumped. Alternatively, an injection profile could have been run after the first stage to determine whether a second stage was necessary.

As the rigless technique proved to be successful in injection wells, it was expanded to include producing wells. Diagnostics for the producing wells are a production log and pump in survey in place of the injection profile. The production log is actually a flowing log rather than a true production log in a pumped down condition, but this information has proven to be reliable enough for successful job design. Jobs on producers LLU 794 and 994 were 200 sx in a single stage because of a rig being on the well. The need for a drill-out is almost certain but incremental rig time is minimal. Based on experience, the common practice is to perforate the open hole and perform a light acid cleanup after drill-out rather than put the well on production to decide whether it needs this stimulation work. Over 2/3 of the producer jobs (including similar jobs cementing under an open hole retainer) have required clean up work, so overall economics favor doing the work while still on the well.

The NCU # 932 workover is a unique producing well treatment as compared to the previous work discussed. Direct communication was identified between this producing well and an injection well located out of pattern. This direct communication was along the known permeability trend in the North Cowden Field. The above mentioned diagnostics were obtained as well as cycling the injection well to help determine the volume of this channel. Once this volume was identified, the decision was made to pump MARCIT gel ahead of the nitrified cement. The gel was pumped at a ratio of five bbls of polymer to one bbl of cement. The MARCIT gel concentration began at 5000 ppm and was increased in stages to 10000 ppm. The nitrified cement was staged from 250 scf/bbl to 50 scf/bbl, followed by cement w/1% fiber. This entire volume was pumped down the tubing and the existing flowing packer, then flushed with the foam wiper plug. The guilty WIW was shut-in prior to this producing well treatment. This type of job requires careful coordination between operations personnel, two different pumping companies and the water suppliers.

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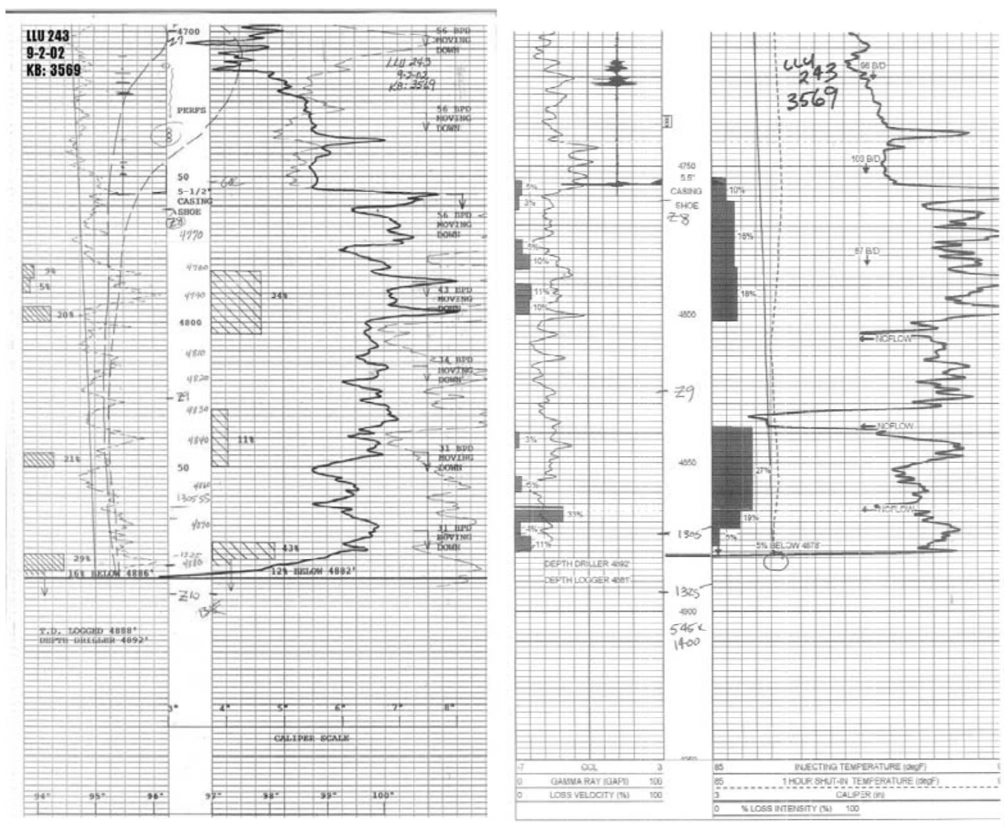
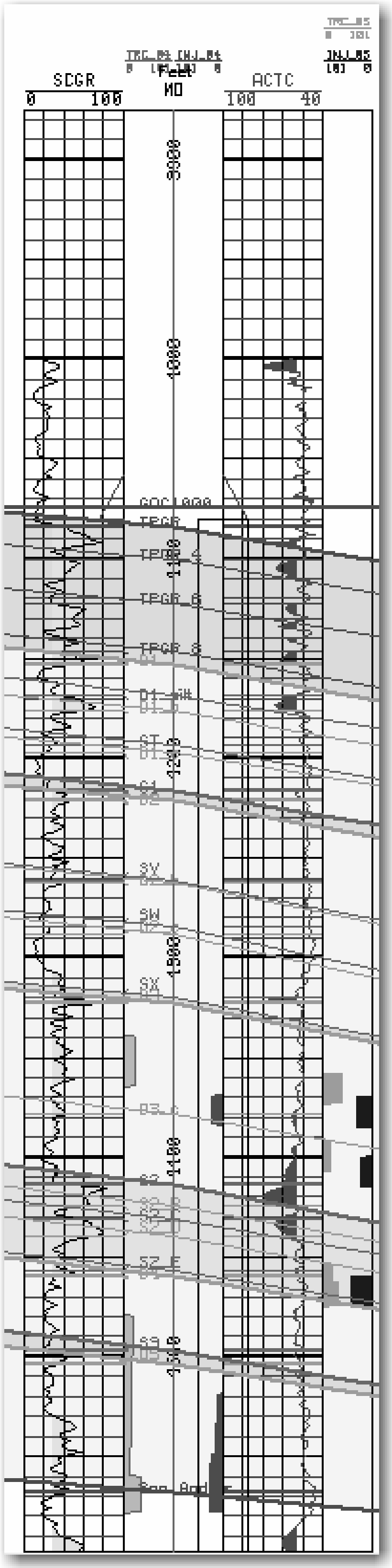
INJECTION WELLS						
	Pre Job		Post Job			
Well	**Rate x Press**	**% Bottom**	**Rate x Press**	**% Bottom**	**Job Pumped**	**Comments**
LLU 274	540x1200	40	350x1350	0	2 stages, 6 bbl Sparksmix each, no drill out	Job was later brokend down by continued pressure increases
LLU 272	800x1300	55	600x1250	45	220# polycrystals, 6 bbl cement, tag high, drill out, perf OH	Poor results on bottom, but improved uphole injection
LLU 243	look @ IPL	45	545x1400	15	220# polycrystals, 6 bbl cement, tag high, drill out	Temperature indicates good bottom shut-off
LLU 511	700x1400	53	250x1550	0	2-12 bbl Sparksmix, polycrystal to seal losses up high, CTU cleanout	55% losses above shoe post job (6% pre-job), sealed off with polycrystal job
LLU 554	450x1300	54	325x1350	0-30	2 - 12 bbl Sparksmix stages, drill out & perforate upper	Post job profile tag 30' above "bottom", 49% below tag depth
NCU 571	1992 X 338	100%	1085 X 346	0%	PB with sand, 4275' to 4210' Then pumped 26 sxs Prem + w/.25% Halad, 2% CaCl, 3% Superbond down inj tbg. Tag cmt @ 4170'	PB w/sand, then capped with latex cmt (acid resistant). Cost = $6,613 (2005)

PRODUCING WELLS						
	Pre Job		Post Job			
Well	**Rate x Press**	**% Bottom**	**Rate x Press**	**% Bottom**	**Job Pumped**	**Comments**

NCU 468	1100 X 700	78%	900 X 700	0%	20 sxs Prem + w/.25% Halad, 2% CaCl, 3% Superbond down inj tbg. Tag, 2nd try = same	Took two attempts – tag depth after first cmt job indicated formation drank all cmt. Cost = $11,260 (2005)
LLU 794	12x620	55	12x200		200 sx Sparksmix, drill out, perf & ZCA job	Additional benefit future reduced CO2 cycling
LLU 994	10x700 TA	55	6x250		50 sx MicroMatrix,150 sx Sparksmix, drill out, perf, gelled acid	TA 2001, lower oil may be due to 6 years shut in cross-flow into upper zones
NCU 932	0 X 2188 (flowing)	100	10 X 60		1200 bbls MARCIT gel (5,000 PPM to 10,000 PPM) followed by 100 bbls cmt 50/50 POZ w/250 scf/bbl N2, 50 bbls cmt w/110 scf/bbl, 30 bbls cmt w/50 scf/bbl, 20 bbls cmt w/1% fiber	Rig-less work down a pkr. This was an RTP – well was SI due to direct communication to WIW, Calculated volume of channel based on response time & rate of offset injection well. Cost = $65,000 (2006)

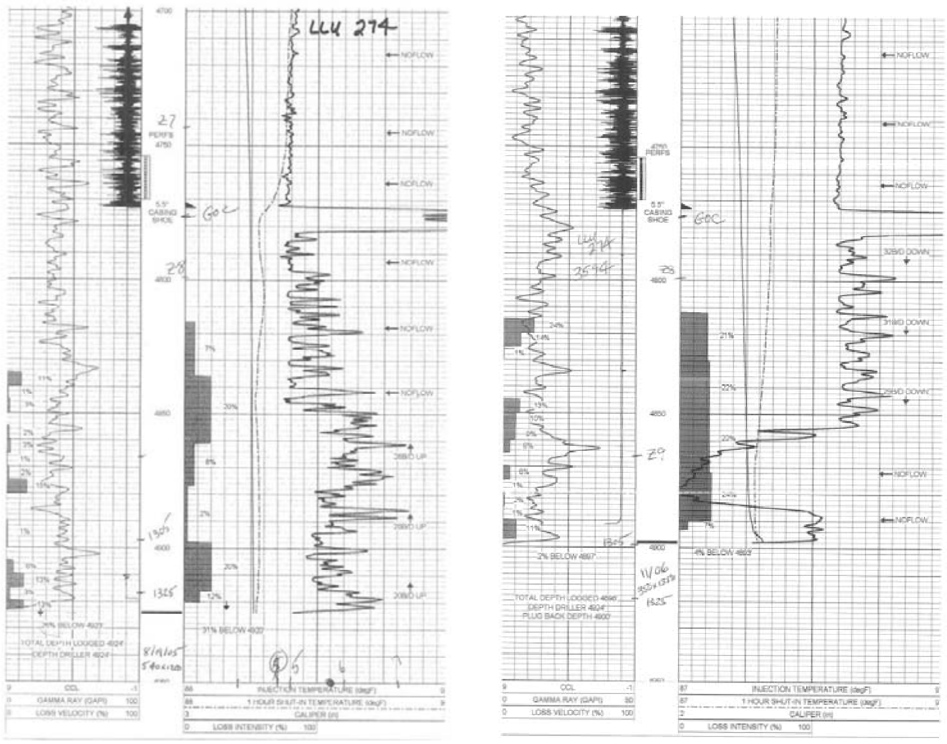


LLU 243 pre-job and after rigless job and cleanout. Significant reduction in injection out bottom, and temperature indicates there is not communication down outside the wellbore. Polycrystals and 6 bbl cement.



NCU # 468 – Pre-work survey is depicted in the middle (depth) column in red & magenta) . This survey shows a large percentage of fluid going into the D5 & San Andres zones. Post job survey is depicted in the far right column in light and dark blue.

A small near wellbore treatment was performed utilizing the foam wiper technique pumped as follows: 20 sxs Prem plus w/.25% Halad, 2% CaCl, 3% Superbond down inj tbg. Pumped wiper plug (nerf ball) and flushed to desired depth. WOC at least 2 hrs, Tag with slick line. Had to pump a second slug with the same recipe. WOC, Tagged PBTD at desired depth. Cost of job was $11,250. Previous plugbacks with the pulling unit rig on the well were costing $62,500. Cost savings of ~ $50,000.



LLU 274 before and after rigless cement job. Bottom injection is shut off, injection pressure increased, and zone 8 (upper) injection picked up in post job injection profile. Pumped two 6 bbl cement stages with TD check after each stage. Estimated savings of $125,000 compared to rig job.

Mr. Looney with the Foam Wiper Technology