SUCCESSFUL LINER CEMENTING IN

LEA COUNTY, NEW MEXICO

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ABSTRACT

A liner is probably the most critical string of pipe set in a well. One of the most common problems encountered in liner cementing is the migration of gas in the annulus during the cementing operation. This can lead to a leaky liner top and a subsequent remedial squeeze job. By using proper cementing techniques and materials, including mud removal procedures, gas migration can be minimized and the need to squeeze liner tops can be reduced.

Recently, several liners were set in wells in Lea County, New Mexico, in which different drilling conditions and problems were encountered (Table I). This paper presents case histories of these wells and the cementing techniques and systems used to combat these problems.

INTRODUCTION/DISCUSSION

Cementing liners is a critical operation. Each liner presents individual problems and several factors must be considered before the actual cementing operation is performed. In this paper, the method used in all of the case histories is the method of placing cement over the entire interval at one time and allowing it to hydrate. Sometimes cement is intentionally designed to not circulate back into the overlap area and a planned squeeze must be performed after the initial job. It was felt that none of the liners to be discussed had such severe conditions that they could not be properly cemented in a single operation. Also, none of these liners had hangers with mechanical packer assemblies. Therefore, it was required that the cement alone contain any gas movement up the annulus which could cause a leaky liner top.

There have been a large number of papers written in an effort to explain annular gas and/or fluid migration after cementing. The industry has come a long way in the understanding of this phenomenon, thanks to the efforts of such authors as Carter and Slagle,[1] Stone and Christian,[2] Christian et al.,[3] Levine et al.,[4] Tinsley et al.,[5] Webster and Eikerts,[6] Sabins et al.,[7] Griffin et al.,[8] and Cheung and Beirute.[9] There is still much to be learned or proved by field experience with regard to fluid or gas migration after cementing.

The liners discussed in this paper (Table I) were cemented using slurries incorporating some but not all of the ideas presented by the above authors. All of the slurries had no free water in an API free-water test and all of the slurries contained enough fluid-loss additive to give less than 100 cc/30 min API fluid loss at the bottom-hole circulating temperature. All of the slurries had enough retarder to place the slurry, but set times at both the top and bottom of the liner were relatively short. These basic criteria were met in all cases. There were several variations beyond these standard points and these are outlined in Table II.

The overall goal of any primary cementing operation is to place a sheath of cement where it is needed to protect and support pipe, to contain gas/fluid in zones and then remain stable for the life of the well. These objectives can be accomplished only if the drilling mud is removed and replaced with cement. Liners are extremely difficult to cement because mud removal is difficult. Mud removal is difficult because of the narrow annulus, lack of centralization, lack of pipe movement, and because only one plug can be dropped. Therefore, either a spacer fluid or chemical wash was used on each of the seven liners discussed in this paper.

Formation damage due to cement filtrate leakoff does not normally need to be considered. However, in southeast New Mexico when the Morrow Formation is the producing interval, filtrate leakoff becomes a major consideration. The Morrow typically contains clays which can swell or migrate when contacted by filtrate and can easily damage an already low-permeability formation. Two methods used to reduce cement filtrate damage according to Webster[10] are

1. to reduce the amount of filtrate lost to the formation, and

2. to chemically modify the filtrate to be less damaging.

"An API fluid loss of 200 to 500 cc/30 min coupled with a good mud cake should give maximum protection in most cases." Fluid-loss additives in liner cements not only reduce filtrate leakoff but are believed to reduce gas migration and help to control bridging in the narrow annulus between the liner and wall of the wellbore. "The most common way to chemically modify the cement filtrate is to modify the salinity with sodium chloride or to use a more protective salt such as potassium chloride. Salt in the filtrate decreases the solubility of hydroxide, increases the solubility of sulfate, lowers filtrate pH, and raises the total ionic content of the filtrate." All of the slurries used in this investigation contained fluid-loss additives and some contained NaCl or KCl. The exact formulations are given in Table II.

Accurate laboratory data must be generated on the exact system to be used prior to performing the job. These data must include thickening time at bottom-hole circulating temperature, compressive strength at both the top and bottom of the liner, fluid-loss rate at BHCT, and a free-water test. Rheology may or may not be needed, but the slurry should at least be very mixable and pumpable. This can be evaluated visually by any trained cement testing person during the previous testing.

It is also a very good practice to always batch mix liner cements to provide uniform cement throughout the entire interval to be cemented. All of the liners discussed were cemented using the batch mixing technique.

JOB RESULTS

The success or failure of the jobs described in this paper were based on several factors. In all instances, the liner tops were pressure tested. In several cases, bond logs were available. In one case, a stimulation treatment was surveyed to determine fluid containment. Another interesting factor was the presence or absence of cement on top of the liner. Last, were any unexpected fluids being produced which could be from out of the zone of interest?

Well 1

Hard cement was drilled from the top of the liner and the pressure test showed no leaks. The well is not producing, but there were no signs of any cement problems. The well was not bond-logged.

Well 2

No cement was found on the liner top. The pressure test did not hold and, in fact, gas was leaking at the top. A bond log showed the cement top at approximately 13,800 ft or 1,500 ft below the liner top. Although no loss of returns was noted during the job, at least a partial loss of circulation is the best explanation for such a low cement top.

Well 3

Hard cement was found on the liner top. The pressure test held. No gas was produced from the liner top. The bond log showed cement over the entire interval.

Well 4

Hard cement was found on the liner top. Some cement was found back down inside the liner at around 14,000 ft. The liner top was pressure tested and held. No gas leakage was noticed. The bond log showed fair to good bond over the entire liner.

Well 5

No cement was found on the liner top. The top did, however, hold on a pressure test. The well was not bond-logged. No gas leakage has been noticed.

Well 6

Hard cement was found on the liner top. The liner top was pressure tested and held. Fluid survey after treatment showed zone isolation by cement. No gas leakage has occurred at the liner top.

Well 7

Hard cement was found on the liner top. No bond log was run. The top was pressure tested and held. No gas leakage has been observed.

CONCLUSIONS

1. Deep liners in Lea County, New Mexico, can be cemented in one step in most cases.

2. A cement slurry with a density substantially heavier than the mud can be used. This should aid in gas migration control.

3. Fluid-loss additives should be used on every liner job.

4. Formation damage control should be considered when designing the slurry.

5. A relatively simple slurry (cement + fluid-loss additive + retarder + optional NaCl or KCl) does a good job in nearly all cases.

6. Spacer fluids and/or chemical washes should be used ahead of cement.

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TABLE 2
SLURRY DESCRIPTION COMPRESSIVE STRENGTH

Well No.	Slurry Density	Water Content	Yield	No. of Sacks	Spacer Fluid	Thickening Time at BHCT (hr:min)	at BHST (24 hr) Top of Liner (psi)	at BHST (24 hr) Bottom of Liner (psi)	NaCl (% BWOW)	KCl (% BWOW)	Retarder (% BWOW)	Fluid-Loss Additives (gal/sk)	Other Additives (%)	Excess Over Gauge Hole (%)
1	16.4	4.29	1.05	450	30 BBL 13 lb/gal Plug-flow Type	6:15	3,000	1,500	0.0	0.0	0.3	0.4	0.5 Turbulence Inducer	85
2	16.4	4.29	1.05	950	20 BBL 15 lb/gal Plug Flow Type	6:25	3,000	1,400	0.0	0.0	0.3	0.5	0.5 Turbulence Inducer	60
3	12.5	12.43	2.19	225	20 BBL 11.5 lb/gal Plug-Flow Type	4:15	1,200	750	0.0	0.0	0.1	0.4	0.5 Turbulence Inducer + 8% Bentonite	235
	15.6	5.20	1.18	125		3:00	4,000	3,100	0.0	0.0	0.1	0.4	0.5 Tubulence Inducer	
4	15.6	5.20	1.18	450	30 BBL 14.2 lb/gal Turbulent-Flow Type	3:45	3,400	1,800	0.0	2.0	0.1	1 (BWOC)	None	20
5	15.6	5.20	1.18	600	15 BBL 13.5 lb/gal Turbulent-Flow Type	5:10	3,200	1,800	0.0	0.0	0.0	1 (BWOC)	None	65
6	14.8	7.23	1.51	560	20 BBL Chemical Wash w/Fluid-Loss Control	5:00	2,700	700	10.0	0.0	0.2	0.7	0.5 Turbulence Inducer Expanding Cement	50
7	16.4	4.29	1.05	240	30 BBL 13.0 lb/gal Plug-Flow Type	5:30	4,300	3,000	0.0	0.0	0.3	0.4	0.5 Turbulence Inducer	235

TABLE 1
LINER DATA AND WELLBORE CONDITIONS LEA COUNTY, NEW MEXICO

Total Depth (ft)	Liner Top (ft)	Open Hole (in.)	Liner Size (in.)	Mud Density (lb/gal)	Bottom-Hole Static Temp. (°F)	Bottom-Hole Circulating Temp. (°F)	Liner Top Static Temp. (°F)
15,400	12,900	6-1/4	4-1/2	12.2	195	162	177
15,400	12,300	10-3/4	7-5/8	14.0	196	163	170
14,100	11,225	6-1/2	5	11.3	184	156	163
14,900	12,300	7-7/8	5-1/2	13.2	192	160	170
15,000	11,400	6-1/2	4-1/2	12.6	165	139	143
16,000	11,300	6-1/2	4-1/2	14.2	209	170	169
16,350	15,200	6-1/2	5	13.0	216	177	207