CASE STUDY – MANAGED PRESSURE DRILLING

Using MPD to Mitigate Water Flow when Cementing 10 ¾" Intermediate I Casing

CHALLENGE

In a conventional setting, the annulus is filled with overbalanced mud before the cementing procedure. After rigging in the cement head, cement will be circulated to the desired depth, and the heavy mud will be displaced from the well.

Yet, in wells with narrow drilling windows, a cement job is not always feasible with heavy mud in the annulus. This is partly due to annular friction generated when circulating viscous cement. In this case study, the rig used an open pit system while drilling statically underbalanced in a formation at ~4000 ft, known for saltwater flow. In the event of a saltwater influx, pumps were used to transfer brine from the inner reserve to the suction pit, and fluid control was within the rig's allowable operational parameters.

However, this water flow could cause cement contamination if the resulting Equivalent Circulating Density (ECD) is not sufficient to overbalance the water flow zone.

SOLUTION

Managed pressure cementing allows the annulus to be filled with underbalanced mud while holding surface back pressure prior to and at the early stage of the cementing procedure.

This additional pressure can achieve an overall overbalanced Equivalent Mud Weight (EMW) downhole and can help mitigate the possibility of water intrusion.

As the heavy cement passes the bit and gradually travels up the annulus, backpressures incrementally decrease, allowing for operational flexibility to target the desired EMW during the cementing process, thereby effectively reducing the risk of cement contamination.

RESULTS

After the first stage of the cement job, a packer was inflated, and the DV (Deployment Valve) tool was opened. The well was circulated with brine, and managed pressure cementing was utilized during the second stage of the cement job for the 10 ¾" casing in 12.45" open hole.

Figure 1 represents a managed pressure cementing schedule used for the execution of the cement job. The table at the top of the figure dictates the amount of surface back pressure (SBP) that needs to be held dependent on the ECD of the fluids in the annulus.

The cement job was performed at 167 gpm. The annulus was initially filled with brine, a low-viscosity fluid. Based on the rheology of the brine, it was determined using hydraulic modeling that the initial dynamic pressure to be held was 140 psi, and the initial static pressure, in events that the pumps needed to be turned off, was 170 psi.

At 462 barrels, the 11.5 ppg lead cement exits the casing string, hydrostatic pressure in the annulus is increased, and the overall rheology in the annulus is. It is at this point. Therefore, dynamic and static SBP can be reduced. As the cement travels up the annulus, the dynamic and static SBP gradually decreases towards zero.

The graphs following the table are simply a visual representation of the data the table contains. The first graph plots ECD vs. volume pumped (following a provided cement pump schedule), and the second the amount of dynamic SBP and pump rates vs. volume. The third graph tracks the fluid tops of the various fluids being pumped, and the last plots the amount of static SBP required to keep the Equivalent Static Density (ESD) above the target EMW.

CONCLUSION

Utilizing MPC techniques, the well section was successfully cemented without contamination from the saltwater flow.

MPC is used extensively in the area to help reduce saltwater influx and limit high ECD generation during the cement operation.

Further analysis is being conducted to reduce the rheological parameters of the cement with the addition of dispersants. This will aid in lowering ECD towards the end of the cementing procedure to reduce the probability of inducing losses in shallower formations.

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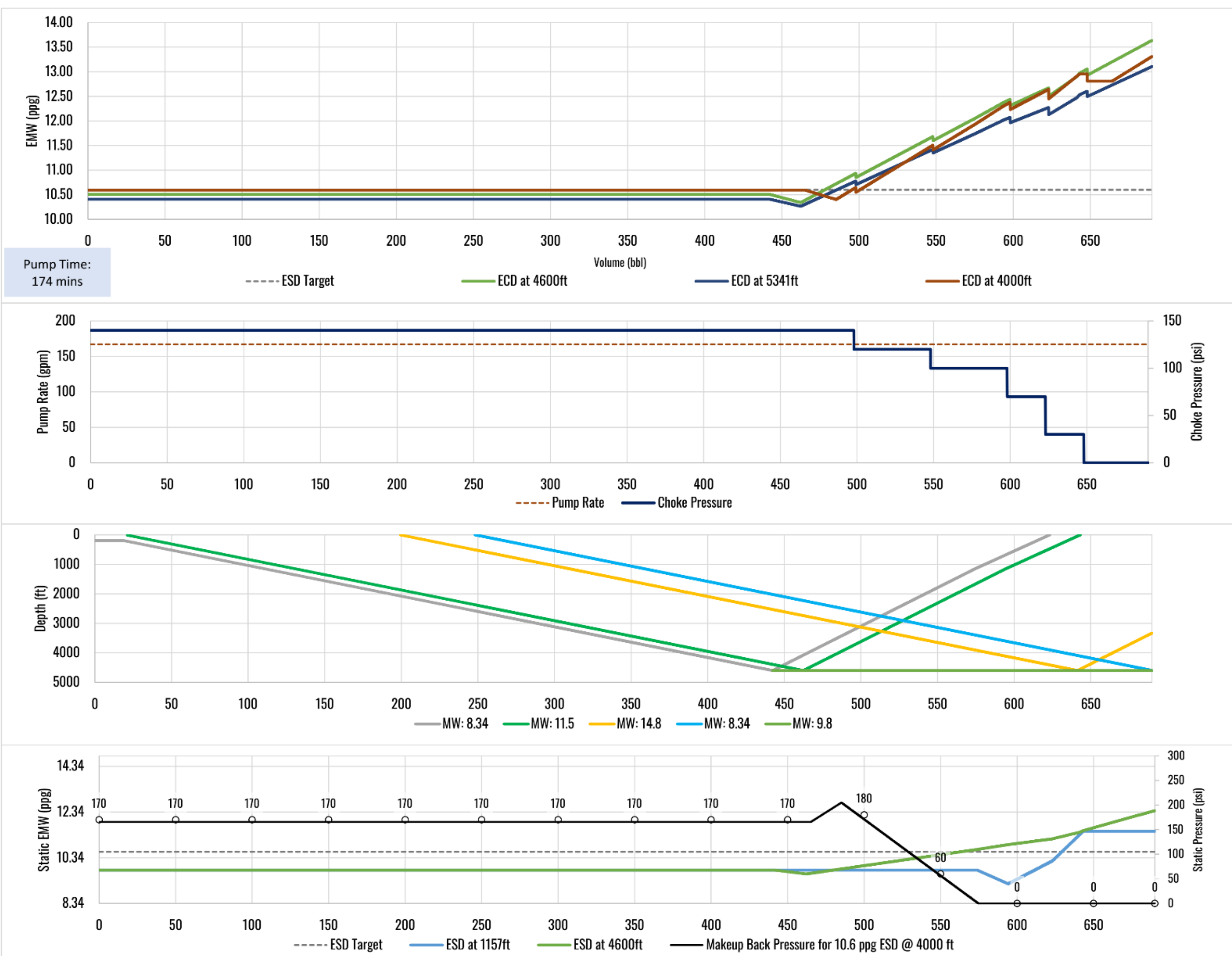
Figure 1: Managed Pressure Cementing Schedule

Managed Pressure Cementing at 4600 ft, Initial MW: 9.8 ppg, Cement MW: 14.8 ppg

Cumulative Volume (bbl)	Flow Rate (gpm)	Dynamic SBP (psi)	Static SBP (psi)	ECD @ TD (ppg)	ECD @ 4000ft (ppg)	Accum. Vol. (bbl)	Comments (Assumed Stroke Capacity = 3.3978 gal/stk @ 100%)
0.0	167	140	170	10.41	10.60	0.0	Start pumping Initial Fluid
20.0	167	140	170	10.41	10.60	20.0	Pump 11.5 ppg fluid at 20 bbl
199.0	167	140	170	10.41	10.60	199.0	Pump 14.8 ppg fluid at 199 bbl
248.0	167	140	170	10.41	10.60	248.0	Pump 8.34 ppg fluid at 248 bbl
442.0	167	140	170	10.41	10.60	442.4	8.34 ppg Fluid starts exiting the string at 442 bbl
462.0	167	140	170	10.28	10.60	462.5	11.5 ppg Fluid starts exiting the string at 462 bbl
498.0	167	120	180	10.71	10.55	498.0	Decrease SBP to 120 psi at 498 bbl
548.0	167	100	70	11.36	11.42	548.0	Decrease SBP to 100 psi at 548 bbl
598.0	167	70	0	11.97	12.23	598.0	Decrease SBP to 70 psi at 598 bbl
623.0	167	30	0	12.13	12.45	623.0	Decrease SBP to 30 psi at 623 bbl
641.0	167	30	0	12.48	12.91	641.4	14.8 ppg Fluid starts exiting the string at 641 bbl
648.0	167	0	0	12.50	12.82	648.0	Decrease SBP to 0 psi at 648 bbl
690.0	167	0	0	13.11	13.31	690.0	Displacement Water to bottom of casing at 690 bbl



Note: Modeled schedules are provided as a guide. Displacements should be conducted as the well dictates in real-time.