



**Flash setting of cement around the drill pipe is a serious hazard, leading some operators to abandon the idea of single-stage cementing or to disengage the setting tool prematurely. But a few precautions can reduce the risk of flash setting to a minimum**

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WITH ALL THE MODERN TECHNOLOGY of equipment and cements, there is still the fear of cement “flash setting” around the drill pipe and cementing it in the hole. This can lead to the “management out of fear” philosophy that no cement will be circulated on top of liners. Some operators have not surrendered completely on the idea of cementing a liner in one stage, but they do disengage from the liner before cementing. It seems it is okay to take the risk that the cement might flash set around the drill pipe, but not to take the risk of being unable to disengage the setting tool from the liner hanger. The authors do not agree with either philosophy.

The problem with using a planned squeeze program on all liners is that a necessarily small volume of cement must be pumped (especially if there is a low displacement efficiency ratio) to avoid getting cement on top of the liner. Unless the liner is relatively long (which means more cement could be used safely, and consequently contact time around the shoe would be increased), chances are that not just the liner top will have to be squeezed, but also the liner shoe. If it is a production liner, a squeeze may have to be performed opposite the pay interval. If there are multiple pay zones, then multiple squeeze jobs could be required. This is a high price to pay for a timid approach to liner cementing. But this is done routinely.

As for single-stage cementing after disengaging from the liner, there is very little insurance gained with this approach. The fear of flash setting cement may be the reason for getting off the hanger before cementing, but very little time is gained by being detached from the liner. If the cement flash sets, the drill pipe will be cemented in the well in either case.

## PREVENTING FLASH SETTING

A flash set liner job does not go wrong because the operator failed to get off the liner, but because the cement set up before it should have. Industry accepts the fact of flash setting cement but does not accept getting caught attached to the liner. Getting off the liner first gains very little and gives up a lot. Disengaging from a liner hanger normally will take less than 5 minutes. One author does it routinely in less than a minute.

With no liner movement, the chances for a channeled cement job increase, probably necessitating a squeeze inside the liner if it is a production liner. With proper planning, the problem of flash setting cement can be minimized.

Flash setting cement is a problem that cannot be overlooked, but neither should it be debilitating. There are no mysterious reasons that cause cement to flash set. Do cements mysteriously flash set in the lab? Of course not. It is believed that cements flash set for one of four reasons:

- Improper pump times due to improper cement testing.
- Incorrect density of the cement mixed on location, which varies pumping times and water loss properties.
- Plugging, and thus elimination of flow, in the annulus caused

by a buildup of cuttings that are carried by an annular velocity that is higher around the liner (due to its larger OD) than around the drill string.

- Superior hole cleaning ability of cement compared to drilling fluid, which causes a cuttings accumulation in the annulus and subsequent bridging in the annulus or around the liner hanger and sudden dehydration of the cement (See Figure 3, Part 1).

There are several measures that can be taken to minimize some of these problems. The first is to ensure that the hole has been circulated clean (this should also include lost circulation material). In the authors' opinion, inadequate hole cleaning is the primary reason for premature setting of cement. This is especially true in hard rock areas where drilling frequently is done underbalanced and with near-water muds that have little buoyancy for cleaning.<sup>1</sup>

Heaving shales cause large washed out sections, and if the shale section is above a consolidated formation, ledges are formed where cutting tend to be isolated from the annular mud flow. The washed out areas can become so large that annular velocities as low as 20 to 30 fpm are not uncommon. Circulating the mud system for days will not clean this type of well bore. Thus, when a liner is run and cemented in this environment, it is readily apparent that the superior hole sweeping efficiency of the cement (due to its higher density and higher rheological values) can cause a cuttings accumulation that can choke off the annulus or bridge against the liner hanger where a circulating restriction exists.

To ensure better hole cleaning by the drilling fluid, its density could be raised to limit the heaving shale problem (this would also limit gas influx if there are right gas zones present that are being drilled underbalanced), which should give closer-to-gauge hole and consequently a higher annular velocity. The higher density mud would also reduce the slip velocity of the cuttings. The yield point, and consequently, marsh funnel viscosity of the system, also could be raised to reduce cuttings slip velocity, as described earlier.

Another prudent practice to reduce cementing problems is to batch mix all cements used for liners. Batch mixing should be insisted on for all critical jobs. This should eliminate fluctuations in the water-to-cement ratio that is so vital for predictable times and water loss values. Also, the cement and mix water used for lab testing should be the same as that used on location. Under no circumstances should circulation be stopped with the liner in the hole before all of the cement and spacer is mixed and ready to be pumped down the hole. On one job, the chemical wash spacer was pumped into the drill pipe before all the cement was batch mixed. A problem developed in mixing all of the cement. While trying to remedy the problem, circulation was held up for 20 minutes. After deciding that the liner could become stuck, we aborted trying to fix the mixing problem and proceeded with the job. Less than half of the cement got mixed, and consequently squeeze work had to be done on the liner top. This is especially critical on long liners where mixing of cement is still going on after the cement turns the float shoe to ensure continuous circulation to help maintain liner movement.

Use low-water-loss cement to minimize circulating pressures on the formation and the chances for sudden dehydration in the narrow annulus or across permeable zones. With regular cement, growth of the cement cake may cause an increase in circulation pressure (See Figure 20). On wells with lost circulation potential, the authors do not encourage density differences of over 0.1 to 0.2 ppg between mud and cement, if possible. This limits free fall, which could cause the fracture gradient to be exceeded, and also make latching up of the drill pipe dart to the liner wiper plug easier to detect. There should then be a pressure decrease when shear occurs. Under no conditions should lost circulation material be added to liner cement, as this could also cause bridging in the annulus.

Once the liner is in position, mud should be circulated around twice surface to surface. During this circulating period, the rheological properties of the mud should be lowered to a safe minimum to increase the mud's fluidity. In particular, the 10 minute gels and fluid loss properties should be minimized.<sup>25</sup> Liner movement or rotating improves the rate and efficiency of moving out dehydrated gelatinous mud. A high-water-loss mud located across permeable zones will dehydrate and become harder to move by spacers and cement. If the mud system is a water-base lignosulfonate, water should be used as much as possible to achieve the desired thinning of the mud, since lignosulfonates act as a retarder to cement. If the well is close to losing returns, we also take this opportunity, while treating the mud, to lower the mud weight by 0.2 to 0.3 ppG (normal trip margin built into the mud density). Screen out all lost circulation material. This increases the chances of circulating cement (if lost circulation is a concern) and should increase the mud's mobility and the displacement efficiency ratio of the cement to mud.<sup>25</sup> Another advantage of conditioning the mud system is to check for washouts that may be developing in the drill string or liner. The authors know of one job where a washout developed in the drill string and cement was returning to surface while cement was still being mixed. The primary cement job had to be abandoned and numerous squeezes performed to cement the production liner adequately. Once the liner is in place, bottoms up should be closely monitored for trip gas, (if any) and that it doesn't arrive much later than it should have. A large delay could be indicative of a washout developing. Of course, pump pressures and pump rates should be continuously monitored while circulating for evidence of a washout. If numerous washouts have been developing in the drill string during the course of drilling the well, consideration should be given to hydrostatically testing the drill string before running the liner.

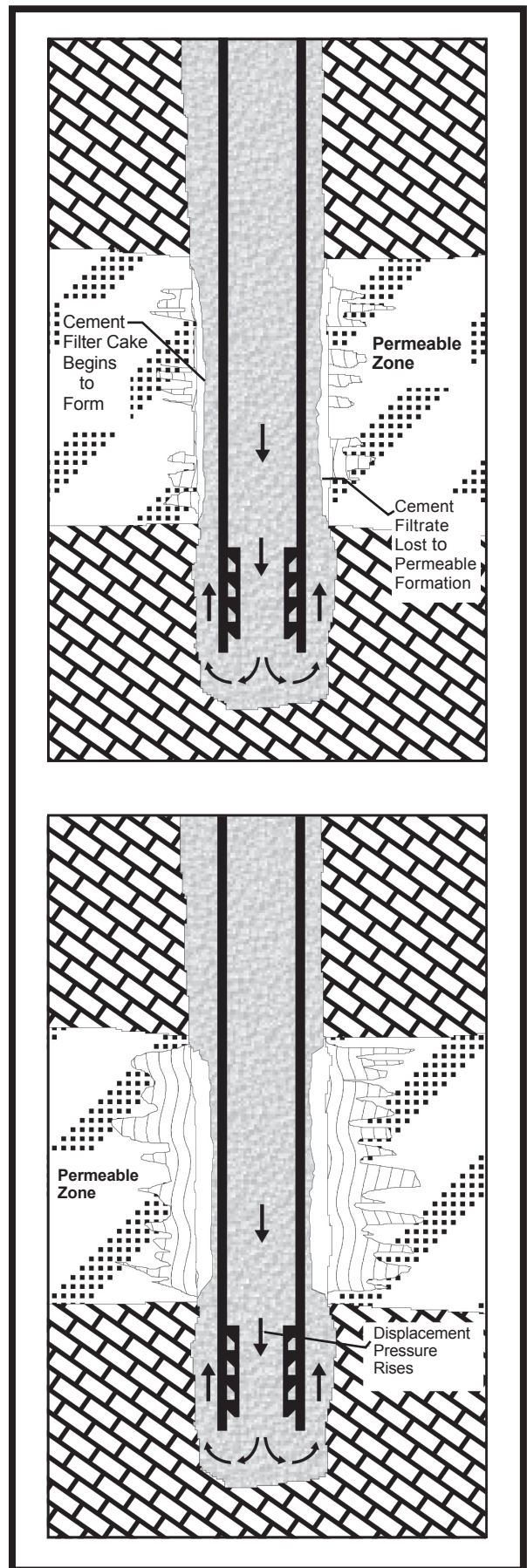
The authors also believe in generous amounts of chemical spacers. We normally run a minimum of 700 to 1,000 ft annular volume of spacer to displace as much mud as possible.<sup>12</sup> This is done to increase contact time around the liner without using a lot of cement so as to limit the height of the cement on top of the liner. If the mud is high density or an oil-base mud, the mud displaced out of the hole by the spacer may also partially offset part of the spacer cost. Money for spacers is money well spent.

If all these precautions are taken, there should be very little likelihood the cement will flash set (or suddenly dehydrate) due to bridging in the annulus or having insufficient pump time.

In the discussion of possible reasons for flash setting cement, one very interesting probability is disguised. Of all the problems that can lead to flash set cement, they should all occur inside the drill pipe, liner or annulus. If precautions described earlier are taken before the liner is cemented, this is extremely unlikely. If cement is going to flash set, then it should happen before it reaches the top of the liner, assuming it was batch mixed, tested properly, the hole cleaned properly, and the cement given adequate pump time.

Another variable that reduces the likelihood of cement flash setting on the liner top is that this is the lead slurry, and thus should be the most contaminated by drilling fluids. Also, the pump time for the lead cement was probably designed for higher bottomhole temperatures and pressures at the bottom of the liner. If the mud is water-based with lignosulfonates as a thinner, then lignosulfonates act as a retarder to the cement's pumping time, further reducing the chances of flash setting. All other cementing problems most likely would occur before the cement gets to the liner top if the pump time was sufficient for the job.

Once cement has been pumped into place properly and the operator has reciprocated or rotated the liner, the next crucial step is to disengage the setting tool from the liner hanger. Together, the authors have had no problem since 1966 of cementing drill pipe in the hole. This includes over 300 liner jobs run by one of the authors.



**Figure 20** - Low-water-loss cements minimize circulation pressure on the formation and reduce the chances of sudden dehydration. With regular cement the growth of a cement cake can cause circulation pressure to increase. (After Syker<sup>37</sup>)

If a problem should occur, there are two remedies that should have been planned for before the job. Pressure relief subs can be run on the top of the liner hanger and set to open with a pressure above the pressure needed to bump the plug, but below the burst rating of the work string. This will allow reversing out of cement in an emergency. We do not recommend this approach because they can pre-shear at too low a pressure, making this approach too risky.

Another alternative is to bullhead a proper amount of mud down the intermediate casing-drill string annulus and force cement through the liner overlap. Care must be taken that enough mud is pumped to clear the annulus around the drill string of cement.

The latter procedure is recommended if the pressure integrity of the intermediate string is felt to be sufficient to allow breaking down the intermediate casing shoe (a leak-off test would be advisable to help in planning). If there is serious doubt about the pressure integrity of the intermediate casing, a pressure relief sub could be considered, but the authors have never deemed well conditions critical enough to justify their use.

On all high-pressure gas production liners, some means of releasing casing pressure should be provided should the liner top fail at a later time<sup>1</sup> (in fact, the precaution should be taken for any string of casing that might not be able to withstand packer or tubing leaks). A choke and bursting-disc type arrangement including pop valves and regulators installed on the casing annulus would be desirable to avoid bursting the intermediate casing should the liner top give way.

Another situation that could arise at a later time on an unattended well is a failure at the liner top that would leak gas but not accept the fluid in the annulus. This could allow the trapped pressure of a gas bubble to rise to the surface and subject the wellhead and intermediate string to a pressure equal to BHP at the liner top. As pointed out by Goins,<sup>37</sup> if gas is not allowed to expand, BHP is on the wellhead at the time the gas reaches the surface.

The cause of liner top leaks and the problems they present will be discussed in greater detail in a future article.

## CALCULATING CEMENT VOLUMES

Calculating how much cement to use on a liner job is much more complex than just reading a caliper. In fact, this can be the most difficult part of the liner design. The combination of both small clearances and large, washed out sections, low displacement rates needed to minimize equivalent circulating densities and the inability on most liner jobs to put heavy cements in turbulent flow makes channeling of cement likely. This makes it nearly impossible to plan the placement of cement columns precisely.

Of course, caliper logs should be the first bit of information gathered before calculating cement volumes. Caliper logs can be run using two-, three-, or four-arm devices, all of which will read the same in round holes, but not in elongated or elliptical holes. For calculating cement volumes, four-arm calipers should be utilized to give the best estimate of hole volume since, according to various logging service companies, hole volumes measured by two-arm and four-arm calipers can vary by as much as 25%. A recent study showed variations in hole volumes between caliper surveys anywhere from 9.41 to 49.86%.<sup>13</sup> This same author came up with some other noteworthy observations. Graves showed that hole volumes after logging can increase on the average as much as 31%.<sup>13</sup> Based on this excellent study, it is easy to conclude that four-arm dipmeters should be run on all liner cement jobs, and that much more cement may be required than calculated hole volumes from calipers would suggest. The economics are there to have as ac-

curate of an estimated hole volume as possible. Equally important is the need to estimate accurately the amount of channeling that may occur. This further illustrates how difficult pumping the right volume of cement can be.

As mentioned previously, liner cement jobs are especially susceptible to channeling. The authors have reviewed liner jobs in different areas and calculated the percent of displacement efficiencies (cement volume divided by annular hole volume).<sup>25</sup> It is seen that the higher the displacement efficiency, the less channeling has occurred, and the lower the displacement efficiency, the more channeling has occurred. We have found displacement efficiencies as low as 20% on some liner jobs and as high as 100% on one job (there was 100% bonding to the top of the cement). One study showed displacement efficiencies between 60% and 93% despite rotation of the liner on most jobs.<sup>18</sup> The authors witnessed a job in which cement was reversed close to 2,000 ft above the top of the liner when the job had been planned for only 200 ft of cement on top of the liner. As can be seen, accurate prediction of where cement is going to end up can be very difficult. Of course, the higher the displacement efficiencies, the better the chances for a primary cement job in the appropriate places and the better the chances the cement top will be where it was planned.

Hard and fast rules are hard to quantify when figuring percent excess of cement to pump on liner jobs. As reported by Arceneaux,<sup>14</sup> cement volumes for the one-stage technique are determined from the caliper or integrated hole volume, with an excess of 15% to 30% added, the volume in the liner overlap and 200 to 300 ft above the liner top. This goes along with Graves<sup>13</sup> post cement findings. Two other large variables should be considered—the displacement efficiency and the length of the liner.

For instance, assume we wish to cement a 500-ft 7 5/8-in liner in a 8 1/2-in hole that is washed out to an average hole size of 9 1/2-in. Assume a 200-ft overlap inside of 9 5/8-in 47.0 ppf casing and 200 ft of cement is desired on top of the liner when the job is complete. Assume also that the liner can be rotated and that a displacement efficiency of 80% can be achieved in the open hole. Add 30% excess to the open hole volume for cementing the open hole. Assume the volume of cement left inside the liner is negligible. With 80% displacement efficiency, the top of the cement calculated to end up  $\pm 255$  ft above the top of the liner. Not too bad!

Assume the same variables above except that the length of the liner in the open hole is 4,000 ft. Assume a displacement efficiency of 60% in the open hole (not at all unrealistic on a long liner). This will put the calculated top of the cement at  $\pm 1,086$  ft above the top of the liner. If a loss of circulation potential exists, returns will probably be lost on this well and the amount of pump time needed to safely “run” from the cement if it can’t be circulated out increases.

As noted previously, one well had a calculated displacement efficiency of 20%. The range of displacement efficiencies from 20% to 100% are dependent upon many variables. Common sense must necessarily dictate what percent excess to use. On deep, hot directional wells with no pipe movement anticipated, and where low displacement are dictated because of lost-circulation fears, very low displacement efficiencies can be anticipated and cement volumes should be reduced accordingly. If the holes are straight, the liner can be reciprocated or rotated, and the well allows a pump rate sufficient to put the cement in turbulent flow, an 80% or higher displacement efficiency can be anticipated.

On liners 500 ft or less, we normally recommend 100% excess over calculated hole volume. On long liners, 3,000 ft or more, we would not recommend over 30% excess. Unfortunately, educated guesses are the best we can hope for on some jobs, as they do not always lend themselves to analytical evaluations.

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