Several alternatives are given for cementing liners when lost circulation is occurring and a case history shows how one was successful.

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MANY LINERS are run in environments in which the drilling fluid cannot be circulated, or in which the increased hydrostatic pressure of the cement column could cause lost circulation. This situation makes primary cementing difficult, but there are some measures that can be taken to enhance the chance success.

Every effort should be made, if practical, to cure the lost circulation problem. If returns are lost while cementing, the liner top will have to be squeezed. If it is a production liner and the lost circulation problem is below the potential producing zone, additional squeezing may be needed to isolate the productive intervals. If it is a drilling liner, it could buckle later due to higher temperatures and higher internal mud weights in washouts that were inadequately filled with cement.[1,20,21,23]

The biggest danger is that circulating surges could aggravate the lost circulation problem to the point that the mud's hydrostatic pressure is lowered enough to allow the well to kick. If lost circulation cannot be cured, then every attempt should be made to at least minimize the problem (i.e., cutting mud weight, spotting LCM (lost circulation material) pills, open hole squeezes, etc.). Having to kill a well while running a liner can pose serious problems.

Due to complications in cementing liners with lost circulation problems, it is very important that good intermediate casing points be selected. The fracture gradient at an intermediated casing point may be sufficient to allow safe drilling, but insufficient to allow cement to be circulated around the liner. Thus a later liner cement job should be kept in mind when picking intermediate casing points.

ALTERNATIVES FOR HANDLING LOST CIRCULATION

If well conditions mechanically or economically dictate that the lost circulation cannot be cured, the authors consider four alternatives. One is to run a piggyback packer above the liner hanger (see Fig. 28) and to cement the liner around the bottom conventionally. The piggyback packer then is set in intermediate casing and the top of the liner is squeezed. This allows running the liner, cementing it and squeezing the top all in one trip. Another technique is to run the liner, cement conventionally around the bottom and then make a trip to pick up a packer for squeezing the top.

A similar technique (that the authors have not tried to date) is to bradenhead squeeze the liner top after completing the bottom after the liner top after completing the bottom stage, rather than make an extra trip to pick up a squeeze packer. Three disadvantages of this method are:

- Squeeze pressure is imposed on the entire intermediate string and if it has been worn by previous drilling, it could rupture below the calculated burst rating.

- Breaking down the intermediate casing shoe for squeezing could momentarily drop the mud level, and consequently, the hydrostatic pressure of the mud column, letting the well come in with no control of the well on bottom. If a gas kick occurs, excessive casing pressures could occur while killing the well.

- Spotting cement around the drill pipe, pulling the pipe out of the cement and then squeezing the top of the liner would probably result in a squeeze in which the cement was contaminated with mud.

Another alternative to consider is running a packer on the top of the liner to seal the annulus between liner and casing. As mentioned previously, these packers can be run in conjunction with the liner hanger and set before cementing or can be set after after cementing is complete (see Fig. 26 of last months installment). However, the authors do not consider the use of liner packers as the best alternative to choose for a well with lost circulation. Run with the liner, they impose a circulating restriction causing higher equivalent circulating densities and surge pressures.[1] And should returns be regained there will be an increase in the likelihood that drill cuttings ahead of the cement will bridge in the annulus and squeeze off circulation. A positive pressure test would not be indicative of an isolating cement job in the overlap with a packer. It is possible that the packer could give way at a later time,[1] communicating zones behind the liner with the uncemented liner top. This could present serious problems while drilling is underway or later during the production phase of the well.[1]

For wells in which the mud in the hole can be circulated but cannot be weighted up without losing returns, some operators design cement slurries to precisely control the height of the cement column. The idea is to keep the hydrostatic pressure of the heavier cement below the hydrostatic pressure required to break down the lost circulation zone. This is a difficult task because of the problem of cement channeling on the vast majority of liner jobs. Cement tops, and consequently cement heights, almost invariably end up higher than expected. One way to improve the chances for success with this type procedure is to reduce mud weight by something close to the trip margin being carried with the mud density and mixing spacer cement at the same density as the drilling mud.

Other considerations must be borne in mind if the operator wishes to use a packer run piggyback in conjunction with the liner hanger (see Fig. 28). This enables precise placing of the cement in the overlap during squeezing and means that the well can be controlled downhole should a kick occur while cementing. Although the piggyback packer causes some circulation restrictions, and therefore surging, this surging is minimized by packers that have large circulating bypasses, which are left open while the liner is being run. Some precaution should be taken when piggyback packers are used, including:

- Liner should not be reciprocated or rotated.

- Hydraulic set, right-hand release liners should be run and the packer should have a left-hand set mechanism

- There are tension limits to these packer that will preclude their use on long liners.

- It is recommended that cement or mud flushes be prevented from getting on top of the packer because of the potential of sticking or cementing the packer. This means limited cement volumes and mud spacers, which means lower contact times and lower degrees of cementing success.

- Unlike a liner packer, a piggyback packer can be used to squeeze the top of the liner.

- When the top has been squeezed, the possibility exists that there may be an uncemented interval left between the top of cement from the primary cementing and the bottom of cement from the squeeze on the liner top.

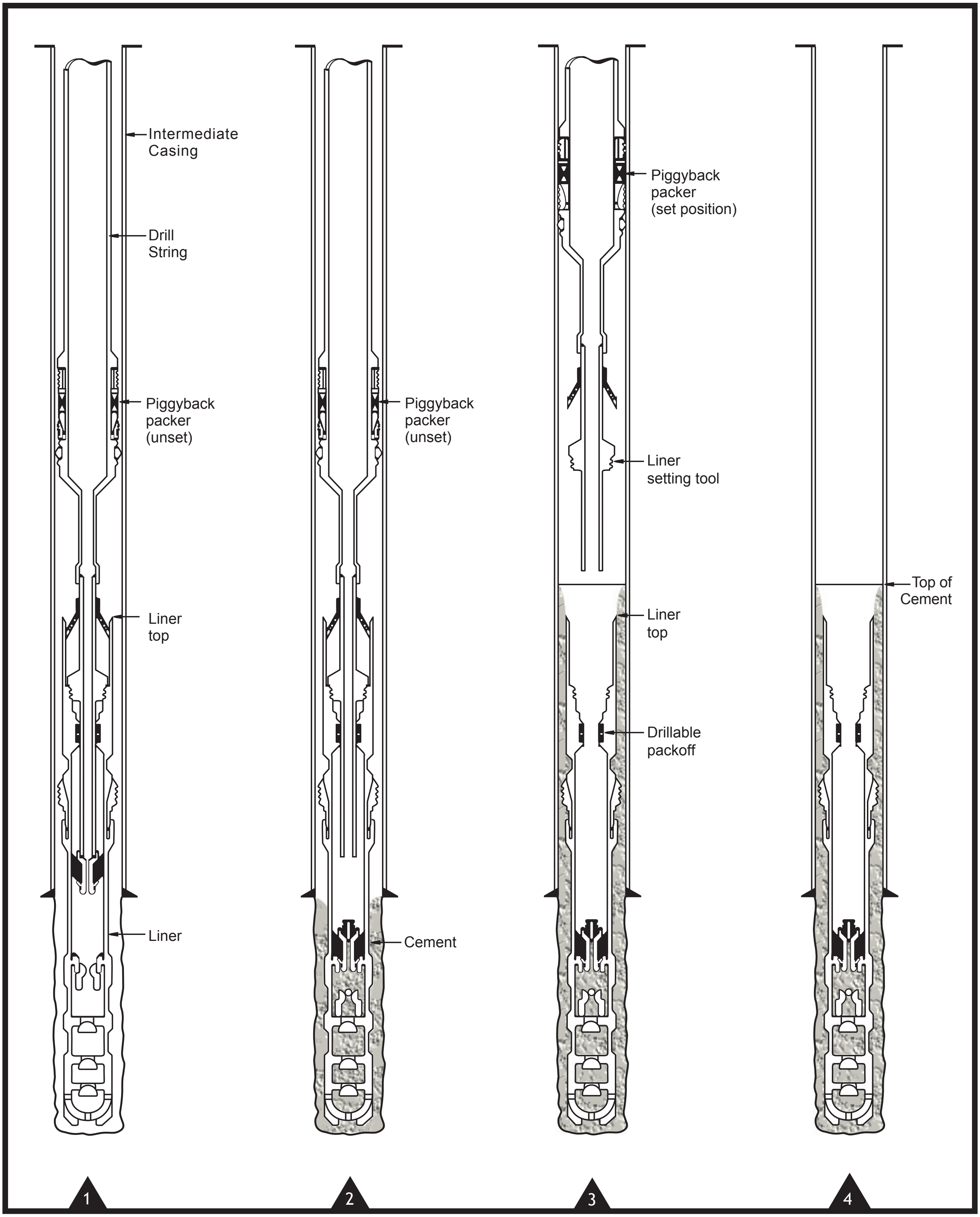

Figure 28 - Sequence used to squeeze a liner using a piggyback backer. **1)** Piggyback backer is run with drillstring, liner hanger and liner. **2)** The first stage is cemented around the bottom and the wiper plug is bumped. **3)** Setting tool is pulled out of liner, packer is set and the liner top is squeezed. Cement is held in the overlap and on top of the liner. **4)** Piggyback packer is unset and the drillstring is pulled out of the hole. (Courtesy of Texas Iron Works, Inc.)

The last point merits further discussion. Since the authors try to to get a complete liner cement job in one trip, the question arises as to how this can be done with limited cement volumes. One solution is to increase the distance that the piggyback packer is run above the liner. On jobs in which the critical isolation is zones is needed most at the bottom, less cement is needed to achieve proper contact time in the area of need and the piggyback packer can be run close to the liner top. The small amount of cement needed should bet be enough to circulate above the liner top.

If the critical area of isolation is near the top of the liner, the piggyback packer can be run father above the liner top to reduce the danger of cement getting on top of the packer while still providing a sufficient amount of contact time. Since a piggyback packer is run when a well is experiencing lost returns, chances are low that returns will be regained sufficiently to allow cement to be circulated to the liner top with this higher spacing of the packer. If returns are regained during cementing, the volume of mud gained in the pits after the cement turns the shoe should be closely monitored. This gain should be compared to the pre-job calculation of the cement volume needed to get it above the liner top. If returns are regained and calculation show the possibility that cement did reach the top of the packer, then drill pipe should be pulled a calculated safe distance above where cement should be. Any cement that may be outside of the drill pipe is circulated out the long way (if pumping time permits) as a precautionary measure. Cement should not be reversed out to avoid breaking down the liner top and losing returns again. The bottom stage of cement then is allowed sufficient time to set before the liner top is squeezed.

LINER JOB DESIGN FOR LOST CIRCULATION

A well in Calcasieu Parish, Louisiana, was to be completed using a 5-in. liner. Well conditions included 7-in. casing set at 9,624 ft, a 6 1/8-in. hole drilled to 10,457 ft TD and mud weights higher than 15.2 ppg could not be circulated—returns were lost twice with 15.3 ppg mud and lost circulation could not be cured. Logs showed a pay zone with an oil-water contact, the productive interval being from 10,019 to 10,022 ft on top of water. Average open hole size from the caliper was 7¾ in.

▸ PROBLEM.

Run a 5-in. production liner and do a maximized liner cement job tailored to well conditions using a 16.5 ppg slurry in a well that had lost circulation problems.

▸▸ *SOLUTION.*

Since the lost circulation could not be cured, it was decided that a piggyback packer would be run in conjunction with the liner hanger for three reasons:

◣ The piggyback packer provided the option of closing the well on bottom should it kick while running the liner. It was felt that this was a possibility because pressure surges running the liner or lost circulation problems while cementing could drop the mud level and let the well come in. Also, the pay interval's pore pressure was estimated to be close to hydraulic mud pressure.

◣ With the severity of the lost circulation problem, it was felt that there was only a slight chance that cement could be circulated to the liner top. Thus the need for squeezing the top was thought to be inevitable.

◣ Being able to close in the well on bottom was considered more important than being able to rotate or reciprocate the liner.

A pressure relief sub run above the liner hanger for circulating out cement was ruled out since the pressure integrity of the intermediate casing and the known low fracture gradient of the 7-in. casing shoe (resulting from the lost circulation problem) meant that the cement could be bullheaded at a relatively low surface pressure should an emergency need arise. This pressure was well below the pressure integrity of the 7-in. casing.

> ***If lost circulation cannot be cured, then every attempt should be made to at least minimize the problem since having to kill a well while running a liner can pose serious problems.***

CEMENT TYPE.

Since the pay zone was determined to be oil, an anti-gas migration cement slurry was not deemed necessary, but rather, a low water loss, regular cement was to be used.

CEMENT VOLUMES.

With an average hole size of 7¾ in., a 5-in. liner and a 20% excess added to the caliper calculated volume, the volume of cement needed is determined as follows:

Volume per linear foot of hole = 0.912 ft^3/ft

Length of liner in open hole = 10,456 (TD) - 9,624 (7-in. setting depth) = 832 ft

Volume to fill annulus + 20% excess = (832)(0.1912)(1.20) = 191 ft^3.

Due to the severity of lost circulation, it was decided that there was almost no chance of circulating cement on top of the liner. Since the liner could not be rotated or reciprocated because of the piggyback packer, the chances for good cement bonding across the pay zone were reduced unless cement pump rates were high and the contact time increased. Therefore, cement volume was increased to 250 sacks (375 ft^3) of class H cement with low water loss additive to give more contact time across the pay zone.

This was 560% excess over gauge hole volume based on the 6 1/8-in. hole drilled. The plan was to reduce the cement volume if returns were regained once the liner was on bottom or while mixing cement. It should be noted that 50% excess over the gauge hole volume often is recommended by the cement service company.

▸ PROBLEM.

Calculate volume gain needed in pits after cement turns the liner shoe to get cement on top of the piggyback packer. Assume a 30% displacement efficiency.

▸▸ *SOLUTION.*

As calculated earlier, 191 ft^3 of cement is needed to fill the annular volume based on the caliper, plus 20%. Assuming a 30% displacement efficiency (due to no planned liner movement) of cement volume to annular volume, the calculation is:

$$(0.30)(191\ ft^3)\ /5.6\ ft^3/bbl = 10.2\ bbl$$

Thus, a ten barrel pit gain is needed after cement turns the shoe to get cement on top of the packer. Any returns at the surface in excess of this amount would mean that the packer will need to be pulled clear of the cement before it is set to squeeze the liner top.

PROBLEM.

Select cement volume for squeezing the liner top.

SOLUTION.

The lost circulation zone was assumed to be close to the 7-in. casing shoe where theoretically the lowest fracture gradient should occur. Due to the severity of lost circulation, the desire to fill the entire 5-in. open hole annulus with cement, and the desire to get a good contact time through the liner overlap while squeezing, 200 sacks (1.50 ft^3 per sack) of low water loss cement were planned to be used for squeezing the liner top. All cement was planned to be batch mixed.

PROBLEM.

Determine cement pumping rate for first stage.

SOLUTION.

The decision was made to pump cement as fast as possible once once it turned the shoe to improve displacement efficiency. A limit of 5,000 psi pump pressure was imposed. Since returned had already been lost, controlling the equivalent circulation density while cementing was not a concern since the lost circulation problem was thought to be close to the 7-in. casing shoe. Consequently, losing returns while cementing would not affect the amount of cement contact time across the pay zone, which was, in this case, most probably below the lost circulation zone.

CENTRALIZERS AND SCRATCHERS

The authors run centralizers on all liner jobs. Scratchers were not used due to the high differential pressures involved and high permeabilities of sands exposed. Scratchers would have decreased the chances of getting the liner to bottom by scraping off wall cake, thus exposing the liner to formation faces, and subsequent possible differential sticking. It was decided to run one centralizer per joint and to allow them to float in the event the liner would not go to bottom. This would help ensure the liner could be pulled back out of the hole.

RUNNING THE JOB

The liner was run slowly into the well an hung off in full tension from 9,208 to 10,455 ft. Returns could not be obtained while trying to circulate with the liner in place. The mud stayed level at the surface while going in the hole. There were no mud returns while running the liner.

The cement job began with 10 bbl of 15.5 ppg mud flush followed by 250 sacks (375 ft^3) of low water loss cement. Cement was pumped at an average rate of eight barrels per minute. The liner wiper plug was bumped up with 1,800 psi. There were no returns through the whole job. Five stands of drill pipe were pulled for safety reasons and the piggyback packer set at 8,743 ft. No circulation was done because without returns, cement could not have gotten on top of the packer (unless a leak developed in the drill string, but bumping the plug and holding pressure was reassurance that this did not happen). The liner top was squeezed with 200 sacks (300 ft^3) of low water loss cement. Final squeeze pressure was 1,200 psi on 15.2 ppg mud. A total of 8 bbl (209 ft) of cement was left on the top of the liner. Pressure was held on top of cement for eight hours to be sure the well was not going to come in. The piggyback packer was then released and pulled out of the hole.

RESULTS

The liner top was successfully pressure tested, both positively and negatively. The cement bond log run showed good bonding across the zone of interest. No *uncemented gap* was found between the bottom stage cementing and the squeezing done on the top of the liner. The well was perforated from 10,019 to 10,022 ft just above the water contact and was completed as a water-free oil well.

The authors considered this successful liner job as an example of turning a problem (lost circulation) into an advantage by allowing more cement (560% excess) to be run past the productive interval. Chances of obtaining a good cement job using only 50% excess of over-gauge hole volume (as was recommended) would have been very low. When cementing with a piggyback packer, high pump rates should be utilized while pumping cement around the bottom of a liner since by this time it is too late to worry about lost returns. In fact, lost returns should be encouraged as long as the lost circulation zone is above the zone of interest. This technique is also worthy of consideration for long liners when there are large differences in bottomhole temperatures between the top and bottom of the liner since it would enable mixing one for the bottom stage and another slurry for squeezing the top which would have lower pump times due to less temperature and pressure.

Due to the better cement jobs achieved by liner rotation, the authors recommend that piggyback packers be run in conjunction with liner hangers *only* when there is almost no chance of returns (as was the case with the above well) or when a well has a gas sand that could come in and that could potentially create excessive casing pressure while killing the well. If the operator is confident of a high burst rating of the intermediate casing, then this should not be a factor. Otherwise, the authors recommend that a mechanical set hanger (All liner hangers should be checked for the maximum bypass area. There is a large difference among different brands) be run to enable rotation or reciprocation. This will reduce the equivalent circulating density while cementing[13] (see Fig. 29). If the liner can be run without losing returns and circulation can be established by reducing the mud weight by a fraction of the trip margin, chances will be good that a primary cement job can be obtained in one trip.

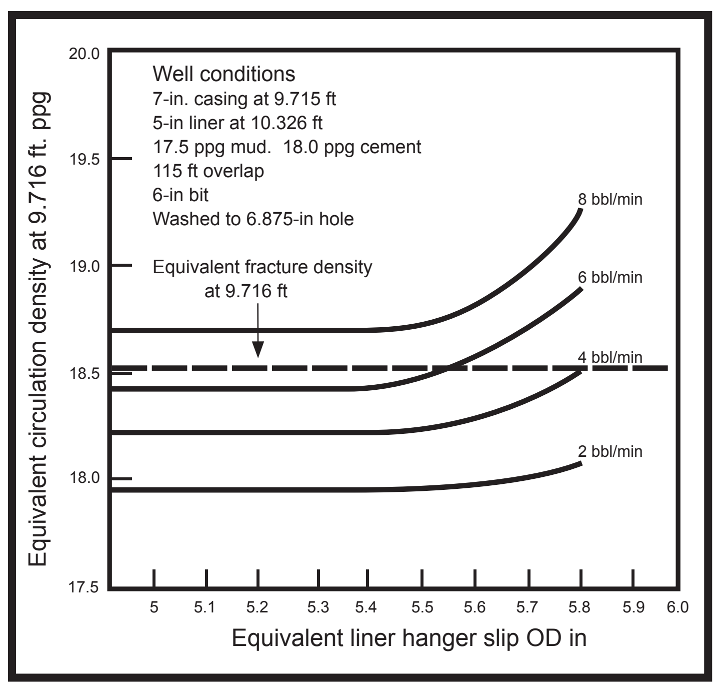

Figure 29 - The equivalent circulating density imposed at the intermediate casing shoe can be increased by setting the liner hanger before cementing. This added restriction can cause lost circulation or bridging over of cuttings in the hanger area. (After Graves[13])

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The authors would also like to state that they have read so much literature and talked to so many people concerning the subject matter that they realize that the manuscript does not completely constitute original thinking. Any credit not given to previous authors where credit is due is regretted and unintentional.

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ADDITIONAL INFORMATION

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