12

Primary Cementing Techniques

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12–1 INTRODUCTION

Primary cementing is a technique for placing cement slurries in the annular space between the casing and the boreholes. The cement then hardens to form a hydraulic seal in the wellbore, preventing the migration of formation fluids in the annulus. Primary cementing is therefore one of the most critical stages during the drilling and completion of a well. This procedure must be carefully planned and executed, because there is only one chance to complete the job successfully.

In addition to providing zonal isolation, the set cement sheath should anchor and support the casing string (preventing formation sloughing or caving into the wellbore) and protect the casing string against corrosion by formation fluids. Uncemented steel casing can rapidly corrode when exposed to hot formation brines, hydrogen sulfide, and carbon dioxide. It can also be subjected to erosion by the high velocity of produced fluids, particularly when solid particles such as formation sand are being transported. Lateral loads on poorly cemented casing strings can result in ovaling, buckling, or even complete collapse because of overloading at certain points. On the other hand, properly cemented casing is subjected to a nearly uniform loading approximately equal to the overburden pressure.

In principle, primary cementing techniques are the same regardless of casing string purpose and size. The cement slurry is pumped down inside the string to be cemented, exits the bottom, and displaces drilling mud while moving up the annulus. Details can vary from casing to casing; the differences in placement technique are discussed in this chapter. It is assumed that the reader is familiar with the related supporting material presented previously—Chapters 5 (Mud Removal), 8 (Prevention of Gas Migration), 10 (Cementing Equipment and Tools), and 11 (Cement Job Design) in particular. In addition, the reader is referred to Chapter 15 for a discussion of the special considerations related to deviated wellbore cementing, and Appendix C for primary cementing calculations.

12–2 CLASSIFICATION OF CASING STRINGS

A series of casing strings is necessary to complete a well, and produce the desired fluids successfully. The design of the casing program is contingent upon several factors—(1) depth, (2) the sizes of the holes in which the casing strings are to be set, (4) the mud-column and formation pressures, (5) the condition of the formation, and (6) the drilling objectives. The casing string must also be designed to withstand the mechanical and chemical stresses in the well (Lubinski, 1951; Bowers, 1955; API, 1959; Smith, 1987). In this section, the functions of the casing strings, the depths to which they are normally set, and special considerations for each are discussed.

12–2.1 Conductor Pipe

The conductor is usually the first and shortest casing string. Its purpose is to protect shallow sands from being contaminated by drilling fluids, and help prevent washouts which can easily occur near the surface because of loose, unconsolidated topsoils, gravel beds, etc. The conductor pipe also serves as a channel to raise the circulating fluid high enough to return to the mud system. It can be used for the attachment of a blowout preventer (BOP), should gas sands, for example, be encountered at shallow depths. The conductor pipe serves to protect the subsequent casing strings from corrosion, and may be used to support some of the wellhead load when the ground support may be inadequate.

At offshore locations, or during swamp barge operations, driving the conductor into the ground is a common practice. The drilling rig is equipped with a pile driver, and sections of conductor casing are welded together as they are driven into the ground. The setting depth is usually less than 300 ft (91 m), and is often determined by the limitations of the pile driver as the conductor begins to

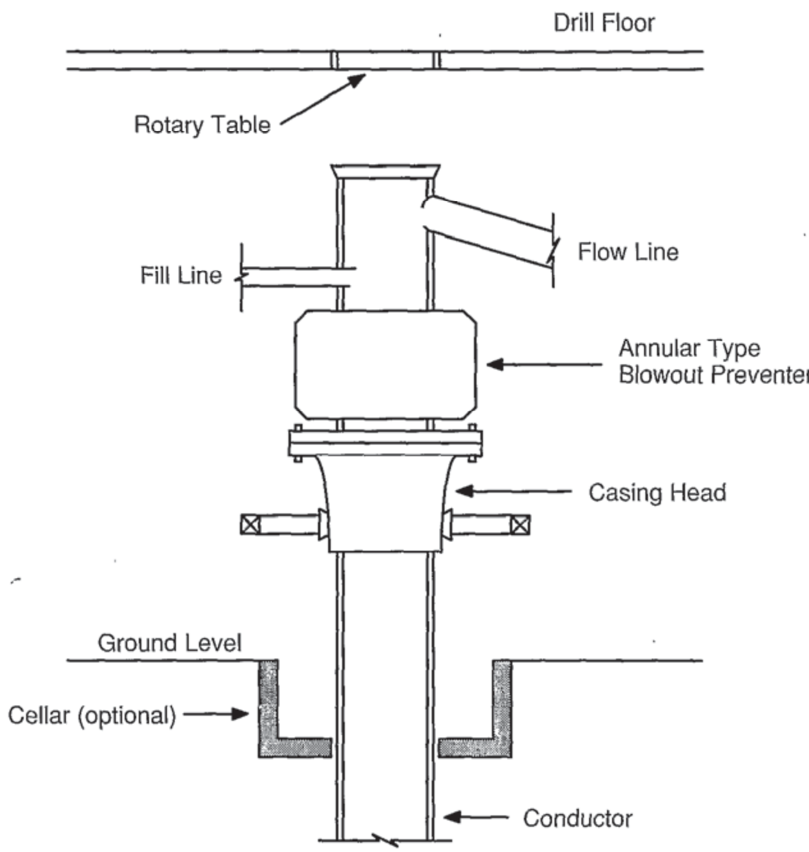

Figure 12–1—Conductor driven into the ground with the casing head welded on, and the annular blowout preventer *connected and ready for drillout.*

encounter firmer ground. Once driven to the maximum depth, the conductor is then cut to the appropriate height below the drill floor (and above the water line in offshore applications), and a casing head is welded into place (Fig. 12–1).

The hole for the conductor is sometimes drilled, and the pipe is made up and lowered in a manner similar to conventional casing. Most often, only a guide shoe may be welded to help lower the conductor into the well. Cementing of the conductor is performed through a swedge which is screwed to the top of the conductor. The cement slurry is pumped through the swedge and into the pipe. Since the length of the conductor is short, the annular and pipe volumes are relatively small, and cement slurry is pumped until returns are observed at the surface. Cement slurry is then displaced from the casing without the use of plugs.

In shallow casing jobs, washouts and lost circulation often prevent the cement from reaching the surface. Under these conditions, using normal procedures, the amount of cement to be used is estimated before the job, then mixed and pumped downhole. If the washouts prevent the cement from reaching the desired height, a "top-up" job must be performed (Section 12–3.2). If lost circulation occurs after the mixing is completed, the casing volume must be displaced, pumping large quantities of cement into the loss zone.

Large-diameter casings are also subject to large upward forces because of the pressure acting on the area of the cement head. If large enough, the upward forces may exceed the buoyed weight of the casing, and pump the casing out of the hole. To prevent such problems, a through-drillpipe (or "stab-in") cementing technique (Section 12–3.1) is often applied.

12–2.2 Surface Casing

The second string of casing, which serves to case off unconsolidated formations and aquifers found at relatively shallow depths, is known as surface casing (Fig. 12–2). In addition to maintaining hole integrity, the surface casing prevents the contamination of fresh groundwater by drilling fluids, subterranean brines, oil, or gas. Depending on the country, there are usually government

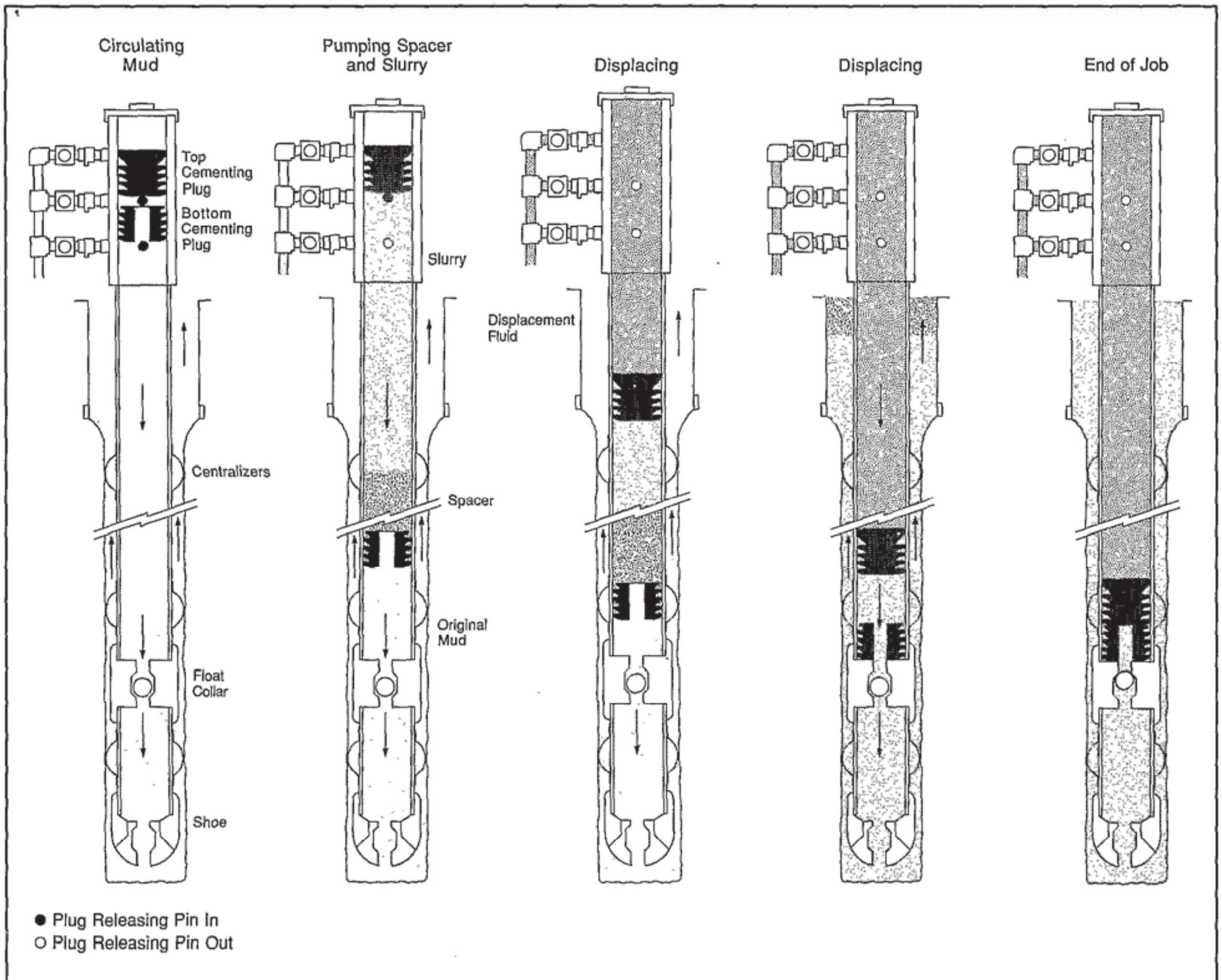

Figure 12–2—Typical one-stage primary cement job on a surface casing string.

regulations stipulating minimum requirements of the casing, and set cement properties (Chapter 11).

Quite often, the surface casing is the first string to which BOPs are connected (Fig. 12–3). Therefore, the selected casing must be strong enough to support a BOP and to withstand the gas or fluid pressures which may be encountered. Surface casing should have the strength to support further casing strings and production tubulars, and provide a solid anchor for the casing head when the well is put on production. Ordinarily, the burst pressure should be equal to one psi per foot of depth to which it is set. The sizes of the surface casing and the setting depths vary considerably; generally speaking, diameters range from 7 to 20 in. (18 to 50 cm), and depths can reach 5,000 ft (1,520 m).

A major problem associated with cementing surface casing is placing the required annular height of cement slurry (often to surface) when the hydrostatic pressures of the slurries often can exceed the formation fracture pressure. The use of low-density slurries and even foamed cement slurries is becoming more common in such circumstances (Chapters 3 and 14). Washouts are another frequent problem. The larger openhole sizes, particularly when enlarged due to washouts, often exceed the capability of caliper tools; as a result, accurate hole volumes may not be determinable.

The through-drillpipe stab-in cementing system can be used in some surface casing cementing operations, but often this is not possible when using smaller size surface casing, or when larger sizes are run beyond 3,000 ft (915 m). Drilling rig design constraints become the limiting factor in these applications.

Frequently, the primary cement job may have to be staged to successfully cement across severe lost-circulation zones or other troublesome intervals. Surface casing strings often must also deal with sloughing shales and shallow gas pockets (Chapter 8). Next to deep liner cementing, it is probably the most difficult casing string to successfully cement. Low formation temperatures prolong the thickening times of extended cement slurries,

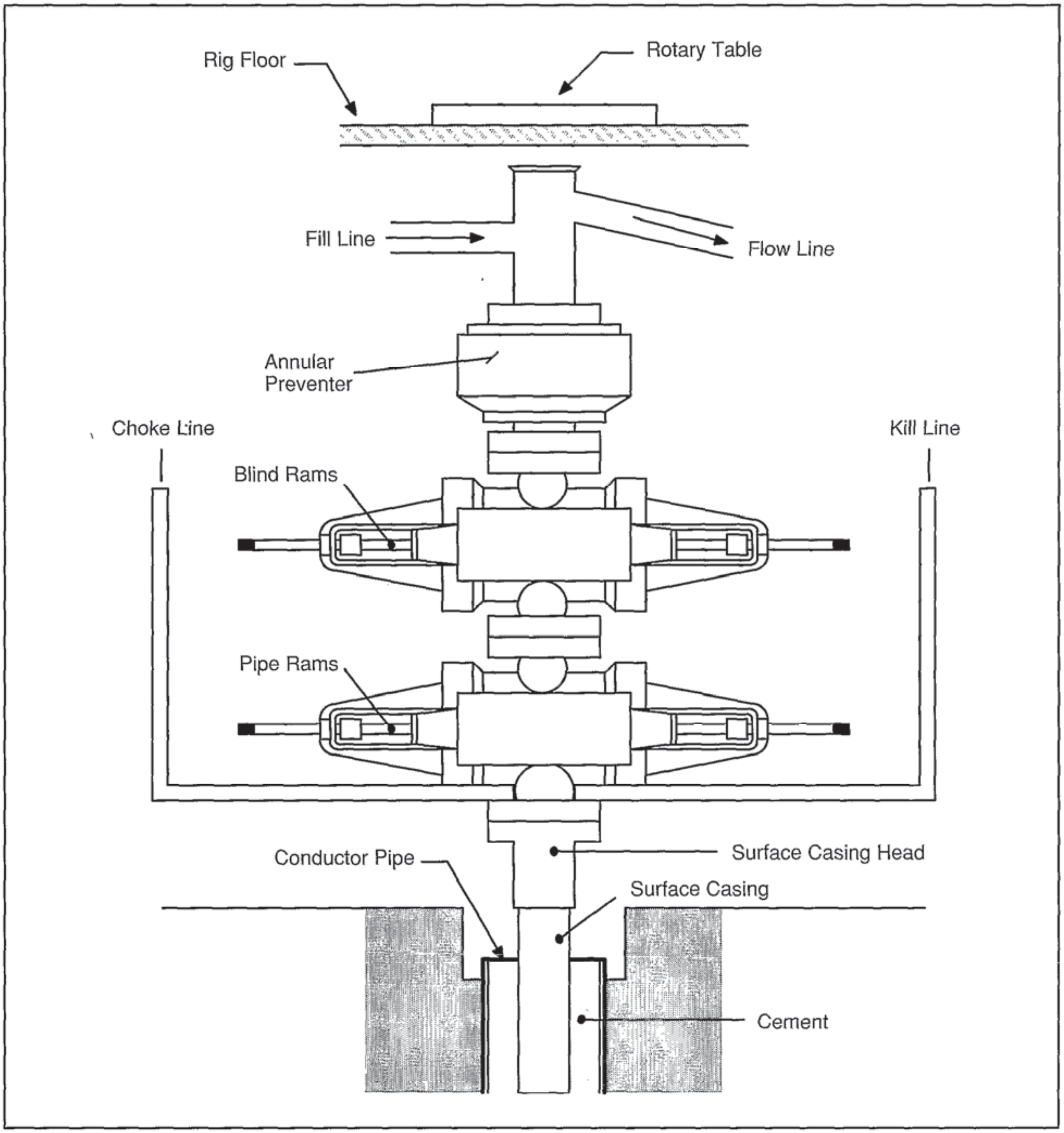

Figure 12–3—Surface casing support of blowout prevention equipment.

and the large annular cross-sectional area (even when considering gauge hole) often makes it difficult to achieve turbulent flow to assure efficient mud removal.

Plug flow should be used as an alternative displacement regime. Plug flow (plug-to-pipe ratio of 0.8) can be accomplished in large annular areas at relatively high pump rates, providing the cement slurries and spacers are designed with high yield points and low viscosities (Chapter 5).

12–2.3 Intermediate Casing

An intermediate casing is often necessary to maintain the borehole integrity as greater drilling depths are encountered. Typical casing sizes range from 6⅝ in. (17 cm) to 13⅜ in. (34 cm), and the depth can vary from 1,000 to 15,000 ft (305 to 4,570 m). Often, the intermediate casing string is the longest section of casing in the well. It is usually run to surface, and once again provides for the anchoring and connecting of BOPs for subsequent drilling.

Intermediate casing is generally employed to seal off weak zones that might fracture with the high-density mud usually needed when deepening a well, and prevent lost circulation. Occasionally, salt or anhydrite formations might cause drilling fluid contamination, or perhaps leach out to such an extent as to cause pipe sticking. Sometimes an intermediate string is used to seal off older producing zones to drill for deeper production. It can be used to protect the hole in deviated sections, and may also be necessary to hydraulically seal high-pressure (noncommercial) fluid zones which may be encountered well above the targeted pay zone.

An intermediate casing also affords better protection against well pressure than the surface string, owing to its smaller diameter. The setting depth of an intermediate string should be sufficient to reach formations which can hold the anticipated mud weight.

This casing string can be cemented in a single-stage primary cement job, but a multistage job is often performed because such a tall annular column of cement slurry would exert a hydrostatic pressure greater than the formation fracture pressure. Figure 12–2 is an illustration of a single-stage primary job. Figure 12–4 depicts a typical two-stage cement job on an intermediate casing string.

12–2.4 Production Casing

Setting this string of casing is one of the principal objectives when drilling a well. In many ways, the production string is the oil well. This string of casing serves to isolate the reservoir from undesirable fluids in the producing formation, and from other zones penetrated by the wellbore. It is the protective housing for the tubing and other equipment used in a well. Tubing may be pulled out of the hole for change or inspection, but the production string is cemented in place. In fact, the manner of cementing this string is usually subject to special attention to assure a pressure-tight bond between the formation and the casing. Common sizes range from $4^1/_2$ to $9^5/_8$ in. (11.5 to 24.5 cm). Depths can vary from 1,500 to over 25,000 ft (460 to over 7,620 m).

The production casing is normally run and cemented through a zone to be produced, and then perforated to allow communication with the formation. Sometimes it is set just above the zone, and an openhole completion is performed. The production casing is normally the last casing set in the well. It may be subjected to maximum well pressures and temperatures, and must be designed to withstand such conditions. The casing should be the best quality (usually the heaviest) pipe appropriate for the conditions involved. A small leak can develop into a blowout, so the threaded connections should be appropriate for the anticipated pressures. The casing joints should be carefully made up as the casing is run into the well to guard against future leaks.

The cementing of production casings is critical. The cement systems must be designed to safely keep the zone under control by providing adequate hydrostatic pressure. Preflushes and spacers run ahead of the slurry must also be checked to assure hydrostatic overbalance and to maintain well control at all times (Chapter 11).

Zonal isolation is imperative to protect the pay reservoir from fluid migration, and to isolate it hydraulically for any future stimulation treatments. In addition, the cement slurry must have adequate fluid-loss control to minimize the amount of filtrate lost to the zone. Good fluid-loss control avoids possible damage of the critical wellbore matrix, and also prevents premature dehydration of the slurry in the annulus, which could result in an annular bridging and a failed cement job. Fluid-loss rates should be less than 100 mL/30 min, and 50 mL/30 min should be strived for (Chapter 6).

An important property of the set cement is compressive strength, particularly across the pay zone. The set cement must also have low permeability to prevent fluid invasion. The rule of thumb for adequate zonal isolation is 1,000-psi (7.0-MPa) compressive strength, and less than 0.1-md water permeability. Strength retrogression must be prevented when the bottomhole static temperature (BHST) exceeds 230°F (110°C) (Chapter 9).

12–2.5 Tapered Casing Strings

It is common in casing-string design to vary the casing weights (internal diameters) within a nominal size range because of load considerations, cost savings, etc. These factors must be known when designing the cement job as burst and collapse ratings are affected, internal diameters vary, and thread connections may change within a particular string.

Another technique is to actually vary the nominal casing size. Combined strings such as 10¾ in. and 7 in. (27 cm and 18 cm) and 7⅝ in. and 7 in. (19 cm and 18 cm) have been successfully used in completions on occasions. There could be various reasons for completing in this fashion, as the end result is similar to a liner type completion. The larger inside-diameter (ID) casing may be desirable in dual completions or in gas wells where additional tubular completion equipment is required, such as side-pocket injection mandrels, etc.

Figure 12–5 depicts a typical tapered string completion. This particular example is completed as illustrated

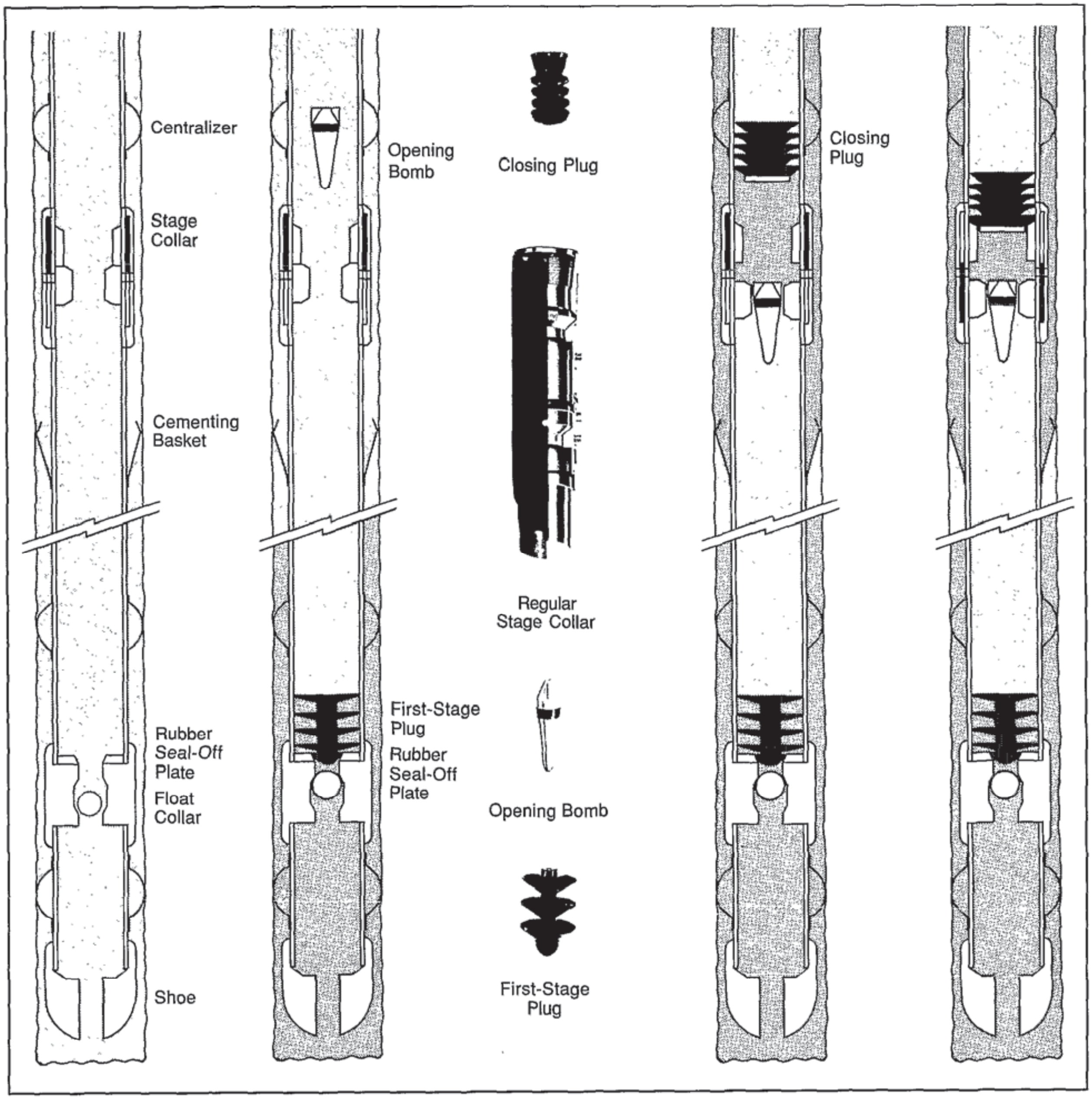

Figure 12–4—Two–stage cementing of an intermediate casing string.

to accommodate an additional tubing string which is run to the bottom of the 7⅝-in. (19-cm) casing, and allows for the circulation of hot oil in the upper portion of the string to prevent the waxing up of the crude produced from the zone penetrated by the 7-in. (18-cm) casing.

The only special considerations are for the displacement plug. The most common practice consists of modifying the displacement plug of the larger diameter casing. This is done by machining down the core of the plug to less than the ID of the smaller casing size. Thus, the wiper fins would aid displacement in the larger diameter casing. Because of their flexibility, they will fold and pass through the smaller casing size. First-stage wiper plugs of the type used in stage cementing could also be considered.

12-3 CEMENT PLACEMENT PROCEDURES

The vast majority of primary cement jobs is performed by pumping the cement slurry down through the casing and up the annulus. Other techniques also exist for solving various well-completion problems. For large-diameter casings, the traditional cementing technique is

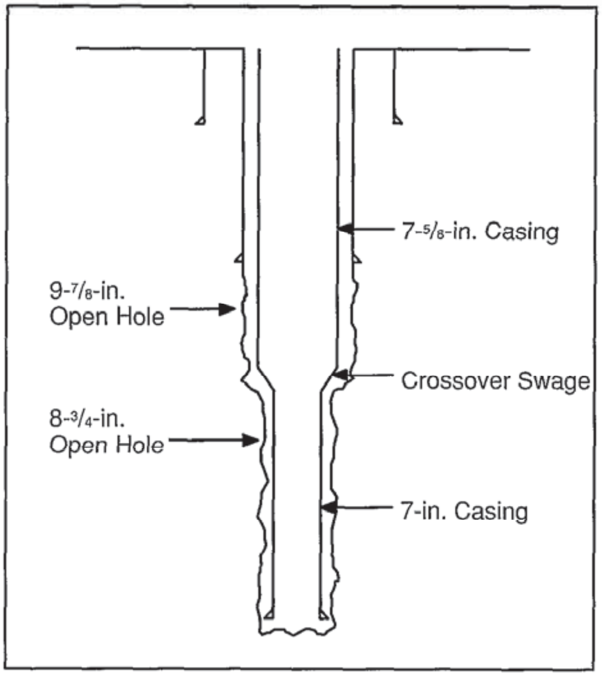

Figure 12–5—Typical tapered string completion.

frequently inadequate; consequently, cementing through the drillpipe or a grouting technique, where the cement is circulated into place by pumping the slurry down one or more small diameter pipes place in the annular gap, is performed. When cementing intermediate or production casings, well conditions and the length of interval to be cemented will decide the placement technique to be used. Usually, the maximum permissible downhole pressures determine whether a job should be performed in a single stage or in multistages. In this section, the most common procedures are described.

12–3.1 Cementing Through Drillpipe ("Stab-In" Cementing)

As discussed earlier, many problems related to the cementing of large casings can be prevented by performing the job through drillpipe. With this technique, the casing is run in place with a stab-in float shoe. The casing is set in the casing slips, thus suspending the string off bottom. Drillpipe made up with a stab-in stinger (Fig. 12–6) is then run in the casing until it is approximately 3 ft (1 m) above the float shoe. Circulation with the drilling fluid is then established, and returns are seen coming from the annulus between the drillpipe and the casing. Circulation is stopped, and the drillpipe is lowered, thus enabling the stinger to stab into and seal in the float shoe. Circulation again is broken, and returns should be observed flowing between the conductor pipe and the casing. Cement is mixed and pumped through the drillpipe and up the annulus until it reaches the surface. As soon as mud contamination is no longer evident in the cement returns, mixing can be stopped and the drillpipe volume displaced. If lost circulation is noticed before the cement reaches the surface, mixing should be stopped and the cement displaced, avoiding the pumping of large quantities of cement into the fractured zone. Care must be taken to avoid collapsing the casing because of excessive differential pressure between the outer annulus and the drillpipe/casing annular space.

Through-drillpipe cementing has several advantages. Accurate hole volumes (most often unknown in conductor or surface holes) are not required, as the cement slurry is mixed and pumped until returns are observed on the surface. This procedure optimizes the total volume of cement mixed and pumped. The subsequent volume displaced from the drillpipe is negligible. This method also eliminates the need for large-diameter swedges and/or cement heads, and also displacement plugs.

Various options are possible with the through-drillpipe stab-in technique. A backup check valve (float collar and float shoe) can be run as depicted in Fig. 12–6. Alternatively, a stab-in float shoe alone could be used. The types of available stab-in tools offer the possibility to latch into the float collar or shoe, thus preventing pump out of the stinger while cementing. Upon completion of the cementing operation, the drillpipe is rotated to the right several turns, and the coarse threads release the stab-in tool. Simpler stab-in tools are also commonly used which omit the latch-in design, and simply rely on the drillpipe weight to hold the stinger in place while cementing.

A further adaptation of through-drillpipe stab-in cementing is possible using a cementing mandrel as shown in Fig. 12–7, with drillpipe (or tubing) hanging freely to within 15 to 30 ft (4.6 to 9.2 m) of the shoe or collar. This type of arrangement offers all the previous advantages with the additional possibility of casing reciprocation. It also eliminates the possibility of casing collapse, because the pressures in the annulus and within the casing are equal.

12–3.2 Grouting ("Top-Up" Cementing)

When lost circulation occurs during large casing slurry displacement, the immediate solution is to recement down the annulus. A small-diameter tubing string is run down the annulus between the casing and the open hole (1⅞-in. [5-cm] tubing is a common size). Several joints can be screwed together, and pushed down the annulus as far as possible. The tubing string is then connected to the cementing unit through a high-pressure treating line, and circulation with drilling mud or water is established.

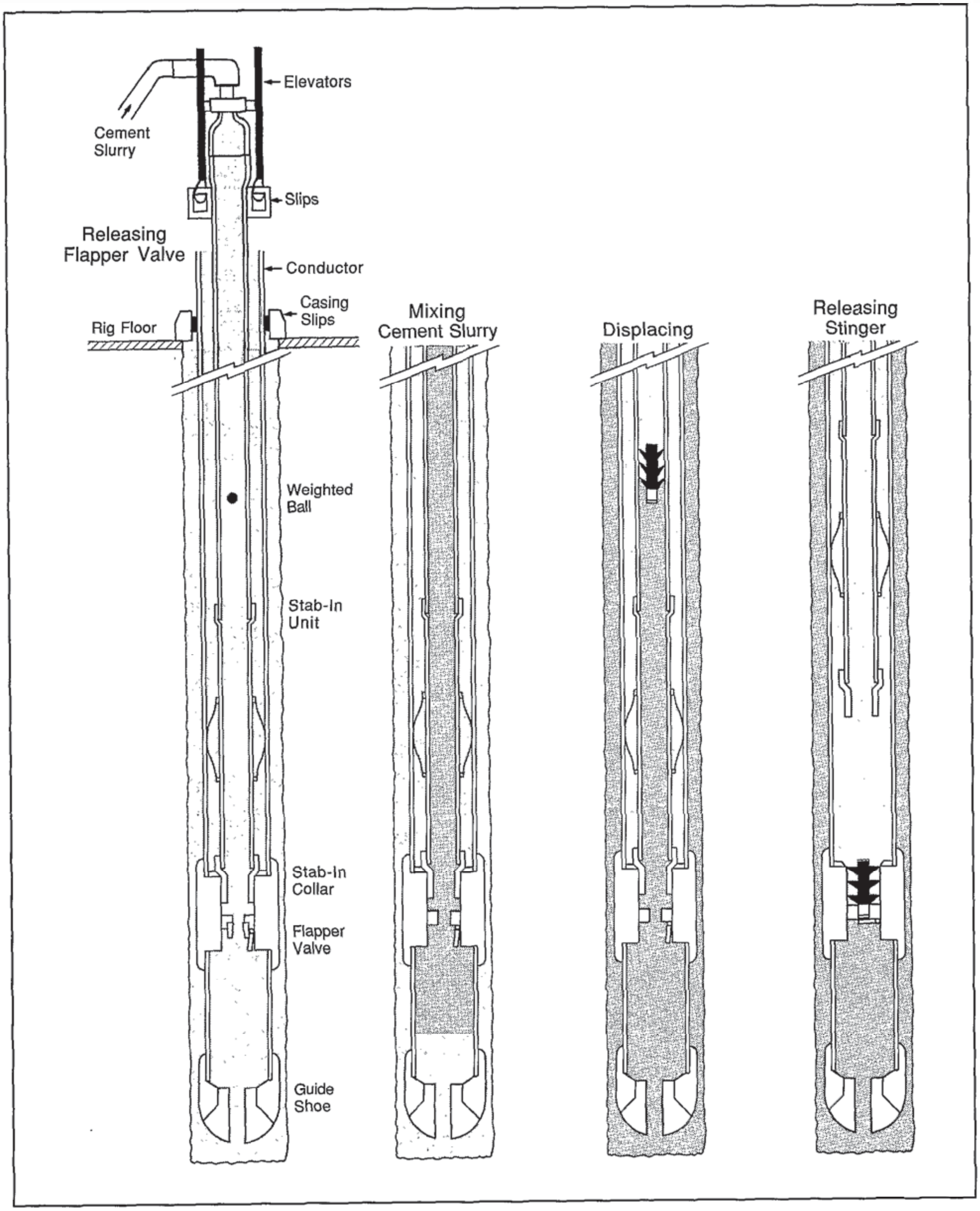

Figure 12–6—Through-drillpipe stab-in cementing.

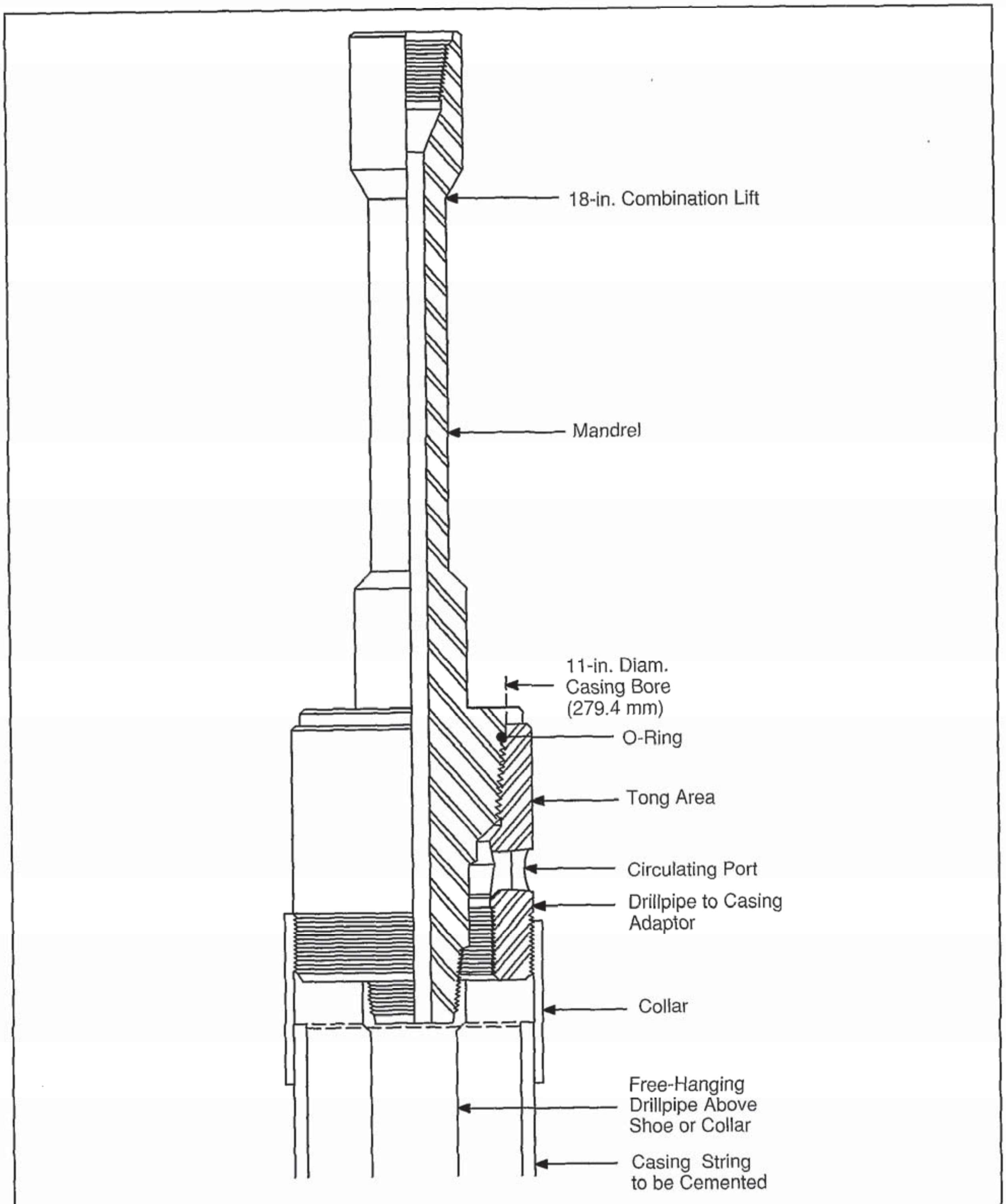

Figure 12–7—*Cementing mandrel.*

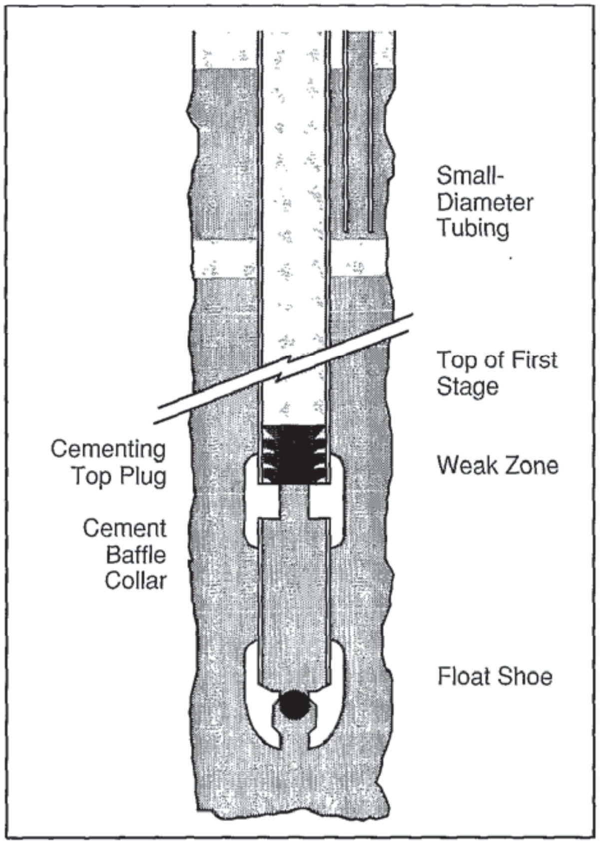

Figure 12–8—Top-up cementing.

Caution must be exercised as friction pressures will be high due to the small tubing ID. Cement slurry is then mixed and pumped in the conventional manner until cement slurry is circulated to the surface. The lines and tubing are flushed with water, and the tubing (if still hanging freely) is withdrawn from the annulus (Fig. 12–8).

The cement slurry can also be mixed and pumped directly into the annulus with the tubing string in place. In extreme cases, such cementations may have to be repeated several times until the cement slurry returns to the surface, and sufficient gel strength is built to support the slurry until it sets.

12–3.3 Single-Stage Cementing

With the development of new ultralow-density cement systems (Chapters 3 and 14), the need for multistage cementing has been reduced. A long column of microsphere-extended or foamed cement can often be placed in the annulus in one stage without the risk of breaking down weak formations.

12–3.3.1 Mud Conditioning

After the casing is in place, the mud is circulated as long as necessary to remove high-gel-strength mud pockets formed during the semistatic period of removing the drillpipe, logging, or running the casing (Chapter 5). Mud circulation is usually performed through the cement head to avoid stopping for an excessive period of time after the mud has been conditioned. Under static conditions, the development of mud gel strength can be fast, and may greatly reduce the mud removal efficiency.

If a single-plug cement head is used, circulation must be stopped prior to cementing to load both cement plugs. The bottom plug must be placed below the lower 2-in. (5-cm) inlet to allow room for the upper plug between the two inlets. If a double-plug cement head is used, both cement plugs can be loaded before starting mud circulation.

12–3.3.2 Bottom Cement Plug

The bottom cement plug serves two functions—(1) it prevents the intermixing of fluids, and (2) it sweeps clean the inner wall of the casing. The most obvious function of the bottom plug is to prevent slurry-mud contamination. However, if properly located, it can also contribute to the conservation of spacer properties. As discussed in Chapter 5, the ability of a spacer fluid to remove mud is crucially affected by its rheology. A small percentage of mud contamination could change its characteristics, reducing its effectiveness.

Another consideration with regard to the location of the bottom plug is the falling of heavy fluids (spacer or cement slurry) through lighter ones (chemical washes). This occurs during the displacement of such fluids in the casing, and its extent depends on the casing size and displacement rates. A bottom cement plug placed between the slurry and the wash will prevent unnecessary contamination due to the density differential effect.

When a spacer is used, sinking of the slurry through the spacer will not occur, because the difference in density is usually not very large. If a plug is run between the spacer and slurry, but not between the spacer and mud, the spacer will become contaminated with mud during the trip down the casing. In addition, the plug will sweep clean the casing wall, pushing ahead accumulated mud film which would contaminate the last part of the spacer. Once the bottom-plug diaphragm breaks, a mud-contaminated spacer will be in contact with the cement slurry—a situation the spacer was supposed to prevent. The ideal situation would be to use two bottom plugs to avoid intermixing of all fluids during the trip down the casing; however, with present plug containers, more than one shutdown would be necessary to load the plugs.

The following sequences are recommended when one bottom plug is used.

- Bottom Plug—Spacer—Cement Slurry
- Wash—Bottom Plug—Spacer—Cement Slurry
- Wash—Bottom Plug—Cement Slurry

12–3.3.3 Displacement Procedures

Dropping the top wiper plug is an easy operation, and should not take longer than the time needed to open and close the valves at the cement head. Cement heads are very reliable tools under normal working conditions, and are designed to minimize time delays. Stopping circulation for long periods of time (5 to 10 min) allows downhole fluids to develop high gel strength which could affect the final result in several ways.

- Additional applied pressure may be required to restart the movement of thixotropic fluids. In extreme cases, this pressure may overcome the fracture pressure, and lost circulation could be induced.
- Poor removal of regelled mud may occur, leading to poor bonding.

The spacer and slurries are then displaced through the casing, isolated between the two wiper plugs. In reality, because of U-tubing (Chapter 5), the top of the cement column may be at a considerable depth below the surface at the time the top plug is released. Depending upon the cement volume and density, and the mud density, the first part of the cement column might have already rounded the shoe. Such phenomena can be predicted by computer programs for cement job design (Chapter 11). The rate at which the cement is displaced into the annulus is not the same as the pumping rate; instead, it varies depending upon the different fluid densities and volumes. This phenomenon continues until the fluid level inside the casing reaches the surface. Continuous flow can then take place.

In general, there is a tendency to disregard the importance of displacement rates during the period of U-tubing. If turbulent flow has been programmed, the maximum pump rate possible is recommended during this period, as downhole fluid velocities are probably one-third to one-half of the surface pumping rate. If plug- or laminar-flow techniques are programmed, the surface rate must be controlled to maintain the desired flow regime. Again, computer programs can calculate the optimum pump rates according to the well geometry and fluid properties.

Once continuous flow takes place, the annular flow rate is equal to the pump rate, and the surface pressure begins to increase as the rest of the cement is placed behind the casing. The displacement then continues at the programmed rate until the top wiper plug bumps in the float collar. However, the pump rate is usually reduced at the end of the displacement to avoid too a sharp an increase in pressure when the plug reaches the collar.

Surface pressure is then released, and the wellhead is opened to test the functioning of the float equipment. If no returns are observed, the line is left open while waiting-on-cement (WOC) for the recommended curing time. If the float-collar valve fails, the fluid returned during the test must be pumped back into the well, leaving the casing pressurized until the cement gels and loses mobility. However, it is very important to release the casing pressure before the cement begins to develop compressive strength, to avoid the formation of a microannulus due to expansion and contraction of the casing.

12–3.4 Multiple-Stage Cementing

Multiple-stage cementing may be necessary for a variety of reasons.

- Downhole formations unable to support hydrostatic pressures exerted by a long column of cement,
- Upper zone to be cemented with (higher density, higher compressive strength) uncontaminated cement, and
- Cement not required between widely separated intervals.

Most of the reasons for multiple-stage cementing fall in the first category. At present, it is not uncommon to cement a longstring to the surface to protect the casing from corrosion. Alternatively, poorly plugged lost circulation zones below the last casing shoe often prevent cement slurries from reaching the surface. Two-stage cementing with the top of the first stage covering the weak zone will permit safe, complete filling of the total annular space.

Three standard multistage techniques are commonly employed.

- Regular two-stage cementing where the cementing of each stage is a distinct and separate operation,
- Continuous two-stage cementing with both stages cemented in one continuous operation, and
- Three-stage cementing where each stage is cemented as a separate operation.

The execution time of stage cementing increases the rig time. Consideration should also be given to the fact that most cement heads cannot accommodate the preloading of the plugs and bombs required in the sequence of operation. As a result, the cement head must be opened to release the opening bomb, assuming the first stage plug was preloaded. The shutoff plug could be loaded after the bomb is released, but caution should be exercised with the types of plugs and compatibility with the cement head. The fit of the plugs should always be carefully checked before the cement job to assure correct fitting of the plugs in the head.

12–3.4.1 Regular Two-Stage Cementing

In addition to conventional casing equipment (guide shoe, float collar, etc.), a stage cementing collar (Chapter 10) is run to the desired depth. There are several types of two-stage collars. It is important to be completely familiar with the operation of the selected type. It is also very important to follow the manufacturer's recommendations for operating the collars. Regardless of the type used, caution must be exercised in the initial handling of the stage collars, as the equipment is manufactured to close tolerances. Smooth sliding and sealing of the concentric sleeves is necessary for proper operation. Rough handling prior to or during installation can "egg" or misalign the moving parts, causing a failure during job execution. One must also be absolutely sure that the float collar and the stage collar are compatible. The first-stage wiper plug (if used) and the first-stage displacement plug must fit and seal against the float collar.

To explain the sequence of stage cementing operations, a brief explanation of the equipment is necessary (Fig. 12–4). Conventional stage equipment consists of the following.

- Stage cementing collar: basically a casing joint with ports which are opened and closed or sealed off by pressure-operated sleeves.
- Rubber sealoff plate: installed in the top float collar to assure a positive shutoff.
- First-stage plug: used to separate the slurry from the displacement fluid, it gives a positive indication of the end of displacement.
- Opening bomb: dropped after the first stage, it is allowed to gravitate to the opening seat in the stage collar; subsequent application of pressure will move the sleeve downward, opening the collar's ports.
- Closing plug: pumped to a shutoff on the closing seat.

Cementing the First Stage—The mixing and pumping of spacers and slurries during the first stage are similar to a single-stage job. After the slurry mixing, the first-stage plug is dropped and displaced until a positive indication of its landing in the float collar occurs. Some operators, when cementing production strings, displace the first stage using two fluids, leaving the casing below the stage collar filled with completion fluid and the upper casing filled with drilling mud. This mud is subsequently used to circulate the hole through the stage-collar ports.

Accurate hole volumes are necessary to determine the correct slurry height in the annulus. If the first-stage slurry covers the stage collar, it can be circulated out when the ports are opened. A caliper log should be mandatory on all multistage cementing jobs. Some types of stage collars allow the use of first-stage wiper plugs. First-stage displacement plugs are mandatory, and must be compatible with the original stage collar and the float collar. Plugs and stage collars from different manufacturers should never be mixed.

Cementing the Second Stage—After the first stage is completed, the opening bomb is dropped and allowed to fall by gravity to the lower seat in the stage collar. Once the bomb is seated, pressure is applied until the retaining pins are sheared, forcing the lower sleeve to move downward and uncover the ports. Usually 1,200 to 1,500 psi (8.4 to 10.5 MPa) will shear the retaining pins. A sudden drop in surface pressure indicates the opening of the ports. This operation could be performed at any time after the completion of the first stage, depending upon the design of the job. If a complete fill is scheduled, the cement from the first stage will be above the stage collar, and must be circulated out of the hole before it develops excessive gel strength.

Once the ports of the stage collar have been opened, the well must be circulated until the mud is conditioned for the second stage. For cementing the second stage, spacers and slurries are mixed as in any single-stage job. The closing plug is dropped after the slurry mixing, and is displaced to its seat in the stage collar. After the plug has seated, a minimum of 1,500 psi (10.5 MPa) above the second-stage displacing pressure is required to close the stage-collar ports. Pressure is usually released from the casing after the ports are closed.

Most second stages of two-stage jobs are performed using low-density filler slurries to allow circulation to the surface. Tail slurries are rarely used even if an openhole section is to be cemented. Protection of the weakest point in the casing string, the stage collar, can be improved by simply increasing the density of the last portion of the cement slurry.

In case of high incompatibility between the cement and mud, it may be desirable to run a wiper plug ahead of the slurry in the first stage. To do so, the following additional equipment must be used for a regular two-stage job.

- Flexible Plug: this special wiper plug is pumped ahead of the first-stage slurry.
- Bypass Insert: located above the float collar or float shoe, it provides a seat for the flexible plug, but allows continued circulation of slurry through its ports.
- Special Insert Collar: located one casing joint above the bypass insert, it provides a seat for the special first-stage plug which follows the cement.
- Special First-Stage Plug: provided with a special head to seal off in the insert collar, it replaces the first-stage plug in the regular stage equipment.

The sequence of operations is similar to the regular two-stage cementing procedure, except that the additional wiper plug is ahead of the first-stage slurry or spacer.

12–3.4.2 Continuous Two-Stage Cementing

Sometimes the situation demands that the cement be mixed and displaced without stopping to wait for an opening bomb to gravitate to the seat in the stage collar. This is known as the continuous-stage cementing method (Fig. 12–9).

The first stage of cement is mixed and pumped into the well. A wiper plug follows the cement to separate it from the displacement fluid. Following the plug, a measured volume of water or mud is pumped. This volume is calculated to displace the cement out of the casing below the stage collar. Allowance must be made for compression, pipe stretch, etc., so that the cement is not overdisplaced around the casing shoe. Overdisplacement is possible because a bypass insert is installed above the float collar on which the cement wiper plug lands. This insert prevents a shutoff when the plug lands, and permits some tolerance in the displacement fluid volume. After this displacement fluid has been pumped, the stage-collar opening plug is released.

The second stage of cement may be pumped immediately behind the opening plug. This slurry is followed by the closing plug. Displacement of this slurry will cause the opening plug to seat on the opening sleeve which will move downward when pressure is applied, opening the collar ports. Further pumping will displace the slurry through the ports and eventually land the closing plug on the closing seat. Application of 1,500 psi (10.5 MPa) above the circulation pressure will close the tool.

12–3.4.3 Three-Stage Cementing

Weak zones combined with gas channeling or potential casing corrosion problems in deep wells could require a three-stage cement job. The basic procedure does not differ from regular two-stage cementing; however, there is one additional stage (Fig. 12–10). The first stage is performed through the shoe, the second through a regular two-stage collar, and the final one through a top stage collar. The first stage is performed through the shoe in the conventional manner, using a first-stage plug to shut off at the float collar. The second stage could be performed at any time after the first, depending upon the cement program.

A regular opening bomb is used to open the ports of the lower stage collar. The well is circulated, and the spacers and slurries are pumped through the ports. The ports are closed using a special closing plug which replaces the regular closing plug. This flexible type of plug passes through the top stage collar, and seats on the lower collar, allowing the application of pressure to close the ports.

The final stage can also be carried out at any time after the second one. An opening bomb (larger than the one used for the second stage) is dropped and allowed to gravitate to the lower seat of the top stage collar. Ports are opened, and the final stage is performed as usual. A special closing plug is then used to close the collar ports.

12–4 LINERS

A liner is a string of standard casing which does not extend all the way to the surface, but is hung from inside the previous casing string. The overlap depends on the purpose of the liner, and could vary from 50 ft (15 m) for drilling liners to as long as 500 ft (152 m) for production liners. Liners can be classified as follows (Fig. 12–11).

- Production Liners: Run from the last casing to total depth, they replace production casing. Cementing is usually critical as zonal isolation is essential during production and any subsequent stimulation treatments that may be necessary.
- Drilling or Intermediate Liners: These are set primarily to case off and isolate zones of lost circulation, highly overpressured zones, sloughing shales, or plastic formations, so that drilling may be continued. Cementing these liners is often difficult due to the circumstances mentioned.

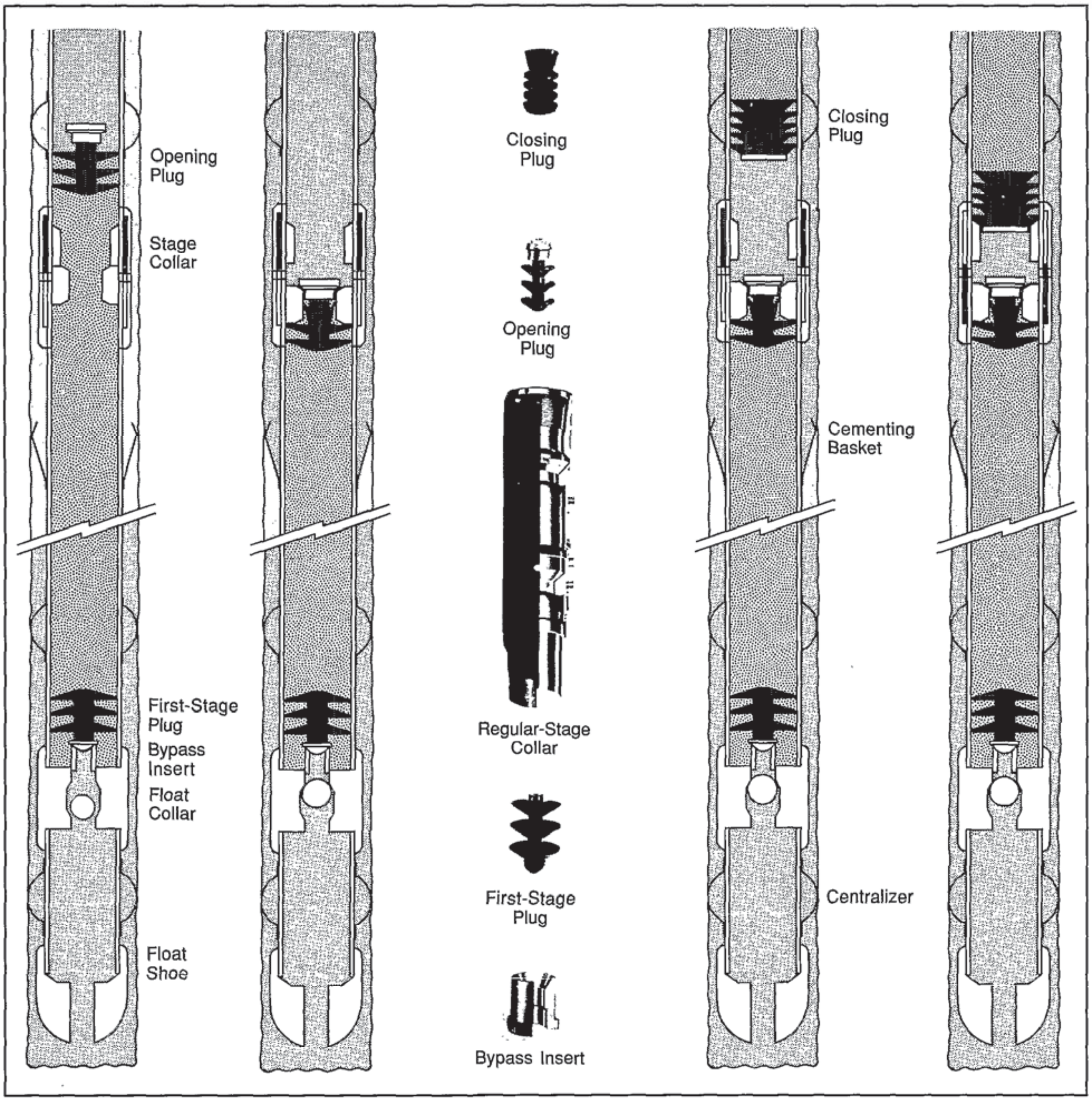

Figure 12–9—Continuous two-stage cementing.

- Tieback Stub Liners: These extend from the top of an existing liner to a point uphole inside another casing. They are generally used to repair damaged, worn, corroded, or deliberately perforated casing above the existing liner, and to provide additional protection against corrosion or pressure.

12–4.1 Running a Liner

The liner is assembled joint by joint at the rotary table, and lowered into the well, just as for a standard casing string. Float equipment is included, and sometimes a landing collar, one joint above the float collar, is used to provide a seat for the liner wiper plug. The dart and plug system must be compatible with the float collar.

Centralizers are critical in liner cementing. Because annular clearances are so small, the liner must be kept clear of the borehole wall. The mud displacement efficiency improves significantly with better centralization. Centralizers also help prevent the liner from differentially sticking while running in the hole, and also allow liner reciprocation and/or rotation during cement displacement.

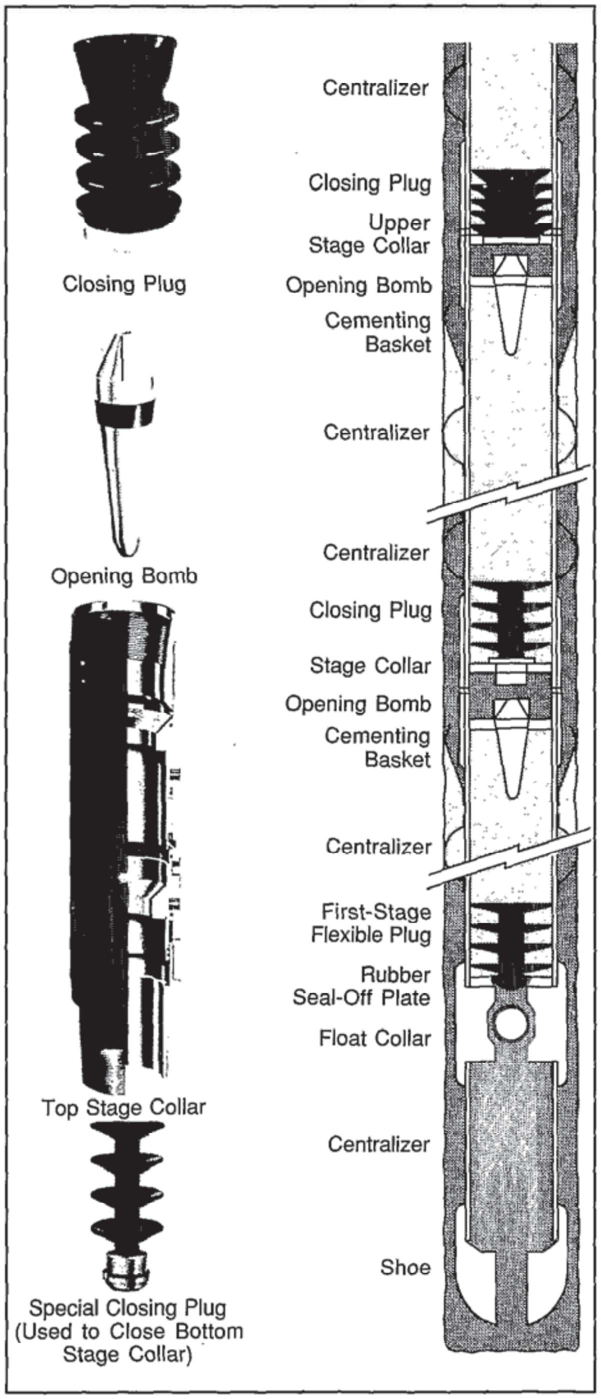

Figure 12–10—Three-stage cementing.

A liner hanger is installed at the top of the liner (Fig. 12–12). When set at the desired depth, this supports the weight of the liner string. Therefore, the liner is kept under tension which prevents it from buckling under its own weight. The liner hangers have slips which, when set, bite into the upper casing and provide the anchor to

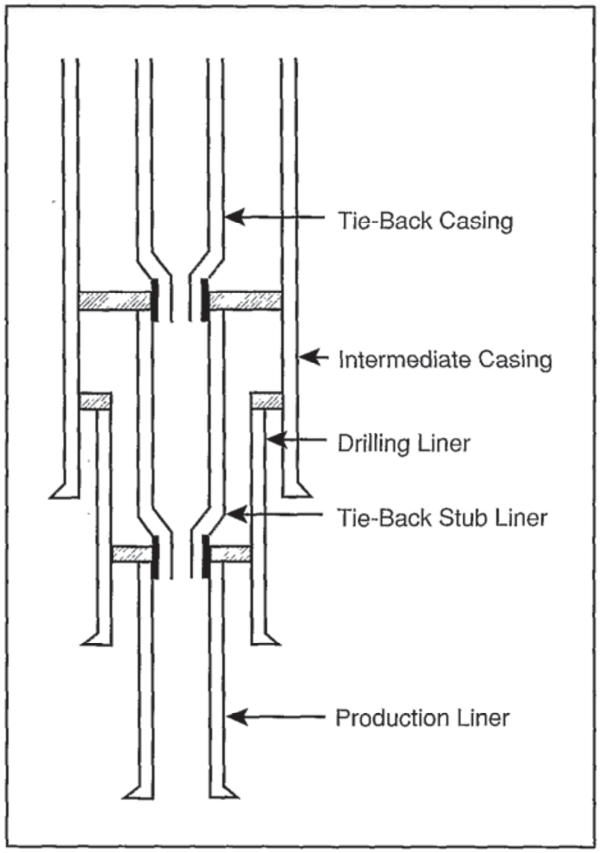

Figure 12–11—Types of liners.

support the liner. The liner hanger remains permanently in place once the liner is cemented.

Liners are usually run into the well using drillpipe and a special setting tool. This tool is retrievable, i.e., it is pulled out of the well with the drillpipe after the liner is run and cemented. It performs the following functions.

- It provides a pressure-tight seal between the drillpipe and the liner. Thus, fluids which are pumped into the drillpipe have to circulate down inside the liner and out of the shoe before returning up the annulus.
- It holds the weight of the liner as it is run into the well.
- It provides attachments for the liner wiper plug. The liner wiper plug, attached by shear pins, has a hole through its center to allow the passage of fluids and cement slurry until the "pumpdown drillpipe" plug closes it. Applied pressure will then shear the pins, and the wiper plug can be pumped down the liner behind the cement slurry.

With the liner at the desired depth, but before the hanger is set, connections are made and the liner and hole are completely circulated with the rig pumps. This

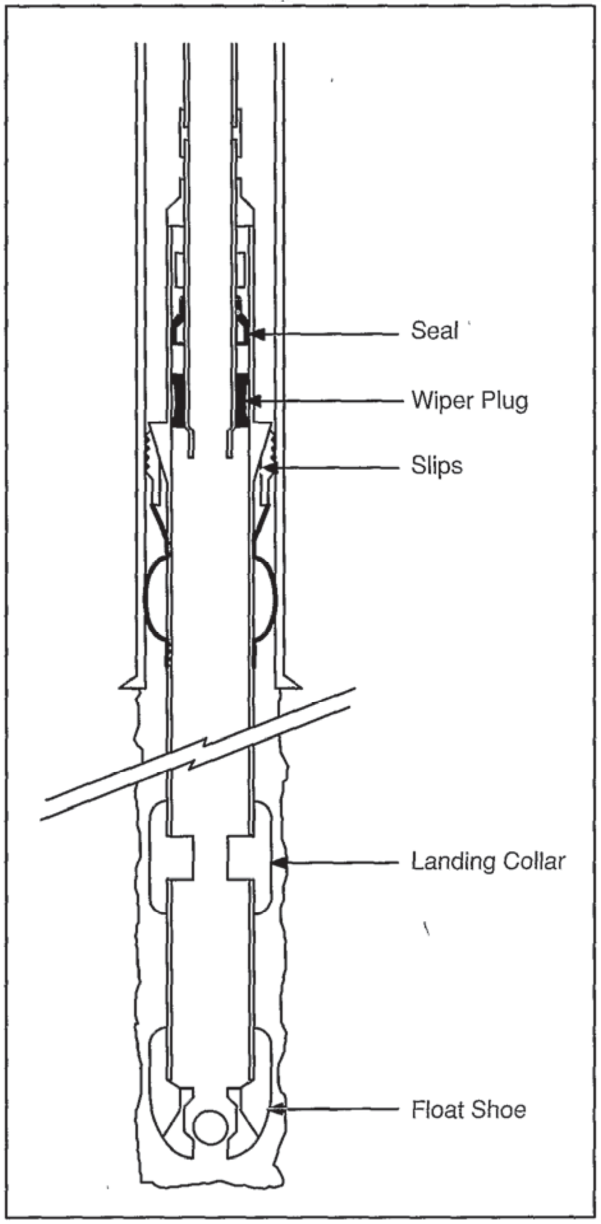

Figure 12–12—Liner setting tool and hanger assembly.

conditions the mud and ensures that circulation is possible before the liner is hung. In some deep liner setting assemblies, a circulation valve is included, which allows circulation to be established above the liner before closing the valve.

Once the mud is conditioned, the liner hanger is set, and the drillpipe and setting tool are then raised slightly to verify that the setting tool is released from the liner. The seal assembly holding the liner wiper plug is usually 10 to 15 ft (3.0 to 4.6 m) long to enable this operation to be performed without breaking the seal between the liner and the drillpipe. This operation must be performed to ensure that the drillpipe and the setting tool can be freed from the liner after the cement is in place.

12–4.2 Liner Cementing Procedures

12–4.2.1 Mud Removal

The success of any cement job depends upon the efficiency of the mud removal. Liner cementing can be one of the most difficult cases. Usually, the annular space is small, and the pipe may not be well centralized. This subject is covered thoroughly in Chapter 5; nevertheless, there are certain points which deserve reinforcement.

A 5-in. (13-cm) OD liner hung from a 7-in. (18-cm) casing inside a $6^1/_8$-in. (16-cm) drilled open hole will have a maximum clearance of $^9/_{16}$ in. (1.4 cm), if the liner is perfectly centered. In some parts of the hole, the annular clearance will be less because of a thin, nonremovable mudcake on the wall of permeable formations. Crooked hole and small clearances between the casing and formation often inhibit the use of centralizers, resulting in eccentration of liners. Under severe conditions, actual borehole contact occurs. Under these circumstances, it becomes much more difficult for cement slurries to remove mud.

It is for these reasons that pipe movement during displacement becomes critical. Bowman and Sherer (1988) reported that less than 20% of all liner jobs include plans to move the liner during cementing. There are many industry misconceptions about liner reciprocation and/or rotation—

- the fear of not becoming unlatched from the liner after cementing,
- a large/stronger drillstring may be required for fear of drill string parting during pipe movement,
- excessive drag caused by centralizers,
- swabbing or surging the pay zone,
- hole deterioration caused by moving pipe, which could lead to annulus bridging, and
- fear that the liner may become stuck and have to be cemented without the designed tension.

In fact, the advantages of liner movement during cementing far outweigh the drawbacks listed above. With the hole in good condition, and correctly selected centralizers on the liner, fewer problems would probably be experienced, and certainly better cementing results would be achieved. Bowman and Sherer (1988) stated that, in their study of over 300 liner jobs, the inability to release the liner setting tool had only occurred twice. One was caused by premature setting of the cement, and the other involved a very early tool design, which has been successfully modified.

In many instances, rotation has advantages over reciprocation. If the liner is in contact with the hole at any point, up-and-down motion would not remove the drilling fluid effectively. However, pipe rotation would allow slurry to be dragged behind the pipe, thus ensuring a sheath of cement around the liner. As stated by Bowman and Sherer (1988), the inability to rotate liners is often due to insufficient starting torque. Once this has been overcome, the torque required for rotation will probably be much less (assuming good centralizer design).

Because of the above problems, it is apparent that the use of adequate volumes of washes and spacers is even more critical in liner cementing than in casing cementing. Maximizing contact time generally increases the chances of a good cement bond, and washes and spacers should be used. In conventional casing strings, contact time can simply be improved by increasing the volume of the scavenger slurry. However, in a liner situation, slurry volumes can be critical, because of the formation hydrostatic limits.

Turbulent-flow-displacement techniques are definitely more efficient for mud removal than plug flow, but care must be taken not to exceed allowable downhole pressures. Fortunately, small annular clearances make it easier to accomplish turbulent flow at low pump rates (Chapter 5). If a job must be performed using plug- or laminar-flow regimes, spacer volumes may be designed to allow for the lower mud displacement efficiency of these techniques.

12–4.2.2 Regular Liner Cementing

The liner cement head and manifold are installed on the drillpipe with the "pumpdown" slurry displacement plug placed between the two inlets. The plug releasing stem holds the plug in the cement head (Fig. 12–13). After the cementing lines are rigged up and pressure tested, the chemical wash or spacer is pumped down the drillpipe. No bottom wiper plug is used ahead of the spacer or slurry. If possible, the cement slurry should be batch mixed to obtain a homogeneous slurry of desired density.

As shown in Fig. 12–14, once the slurry is mixed and pumped into the drillpipe, the pumpdown plug is dropped and displaced to the liner hanger. At this point, the pumpdown plug passes through the liner setting tool, and then latches into and seals the hole in the liner wiper plug. The surface pressure will rise as an indication of the plug landing. Further applied pressure of approximately 1,200 psi (8.4 MPa) will shear the pins holding the liner wiper plug in place. Once released, the two plugs move as one inside the liner as displacement is continued. When the

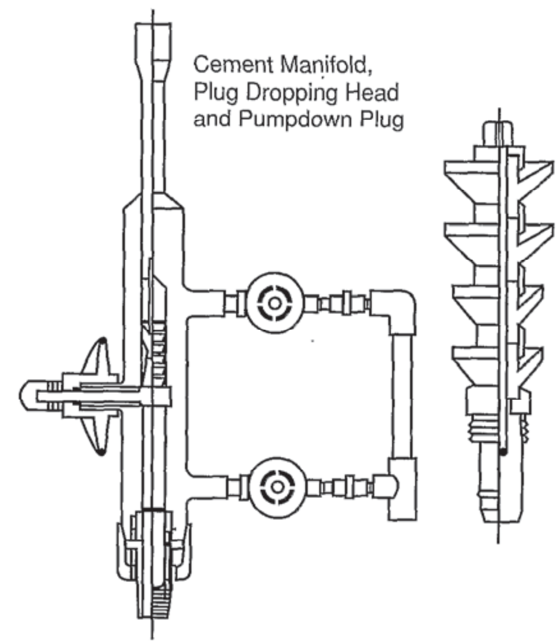

Figure 12–13—Liner cementing head.

internal volume of the liner has been completely displaced, the plugs seat on the float or landing collar, and a further pressure rise will occur, indicating completion of the job. Functioning of the float collar is tested after pressure is released by monitoring the returns.

If a packer-type liner hanger has been used, the packer between the liner and the upper casing is set at this time, the setting tool is pulled free from the liner hanger, and any excess cement is reversed out. If no packer is incorporated into the hanger, the reversing out depends on the quantity of excess cement expected, and whether lost circulation is anticipated. This is an important decision in liner cementing design, as proper isolation of the liner/casing annular space is critical.

The amount of cement excess must be carefully calculated by taking into account the well conditions and operator requirements. The following factors must be balanced.

- Sufficient excess cement must be planned for, if noncontaminated cement at the liner hanger is needed. A four-arm caliper should be run prior to the liner operation, and the slurry volume determined from the caliper logs. A recent study by Graves (1985) pointed out that hole volumes can change by as much as 31%.
- Displacement efficiency also becomes a key variable in determining cement slurry volumes; although

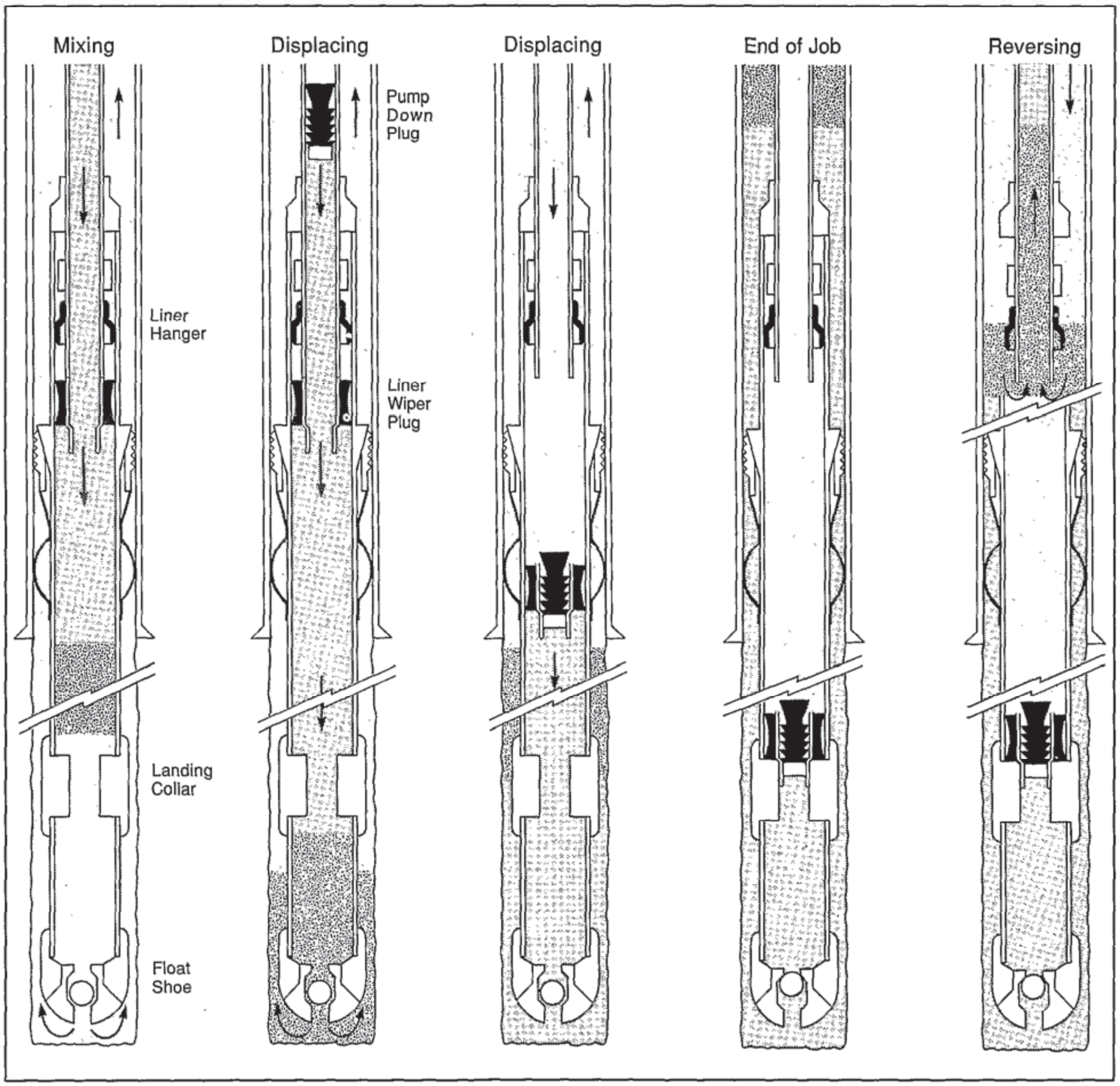

Figure 12–14—Liner cementing.

100% efficiency is the ideal, it is not uncommon to have 60% to 80% displacement efficiency in liner cementing (Smith, 1989). The volumes become more adversely affected the longer the pipe to be cemented.

- If excess slurry is to be reversed out, weak formations could pose a problem. The thickening time of such slurries must be extended to allow for the reversing operation.
- If reversing out is not scheduled, operators usually do not want to drill out long columns of cement; therefore, the excess slurry may have to be limited. This could definitely affect the quality of cement around the overlapped interval.

Once reversing out (or nonreversing) is completed, the setting tool and drillpipe are pulled leaving the cement to cure throughout the recommended WOC time. A checklist for running liners is published in API Bulletin D17, and is reproduced in Table 12–1.

The following procedure is taken from API *Bulletin D17*. The reader will note that it should be modified if the intent is to reciprocate or rotate the liner. The procedure is as follows:

1. Run drillpipe and circulate to condition hole for running liner. Temperature subs should be run on this trip if bottomhole circulating temperatures are not known. Drop hollow rabbit (drift) to check drillpipe ID for proper pumpdown plug clearance. On trip out of hole, accurately measure and isolate drillpipe to be used to run the liner. Tie off remaining drillpipe on other side of the racking board
2. Run_____ ft of ____ liner with float shoe and float collar spaced ____ joints above float collar. Volume between float shoe and plug landing collar is ____bbl. Sandblast joints comprising the lower 1,000 ft and upper 1,000 ft of the liner. Run thread-locking compound on float equipment and bottom eight joints of liner. Pump through the bottom eight joints to be certain that float equipment is working.
3. Fill each 1,000 ft of the liner while running, if automatic fill-up type equipment is not used.
4. Install liner hanger and setting tool assembly. Fill dead space (if packoff bushing is used in lieu of liner setting cups) between liner setting tool and liner hanger assembly with inert gel to prevent solids from settling around the setting tool.
5. Run liner on ____ (size, type connection, weight, and grade) drillpipe with ____ pounds minimum over pull rating. Run in hole at 1 to 2 minutes per stand in casing and 2 to 3 minutes per stand in open hole. Circulate last joint to bottom with cement manifold installed. Shut down pump. Hang liner five feet off bottom. Release liner setting tool and leave 10,000 pounds of drillpipe weight on setting tool and liner top.
6. Circulate bottoms-up with ____ barrels per minute to achieve ____ feet per minute annular velocity (approximately equal to previous annular velocities during drilling operations).
7. Cement liner as follows:________________.
8. If unable to continue circulation while cementing, due to plugging or bridging in liner and hole wall annular area, pump on annulus between drillpipe and liner to maximum ___ psi and attempt to remove bridge. Do not overpressure and fracture the formation. If unable to regain circulation, pull out of liner and reverse out any cement remaining in drillpipe.
9. Slow down pump rate just before pumpdown plug reaches liner wiper plug. Drillpipe capacity is ___ bbl. Watch for plug shear indication, recalculate or correct cement displacement, and continue plug displacement plus ____ bbl maximum over displacement.
10. If no indication of plug shear is apparent, plug calculated displacement volume plus ____ bbl (100% + 1% to 3%).
11. Pull out 8 to 10 drillpipe stands or above top of cement, whichever is greatest. Hold pressure on top of cement to prevent gas migration until cement sets.
12. Trip out of hole.
13. Wait-on-cement ____ hours.
14. Run ____-in. OD bit and fill cement to top of liner. Test liner overlap with differential test, if possible. Trip out of hole.
15. Run ____-in. OD bit or mill and drill out cement inside liner as necessary. Displace hole for further drilling. Spot perforating fluid (if in production liner) or other conditioning procedures as desired.

Table 12–1—Liner running procedures checklist (from Bowman and Sherer, 1988).

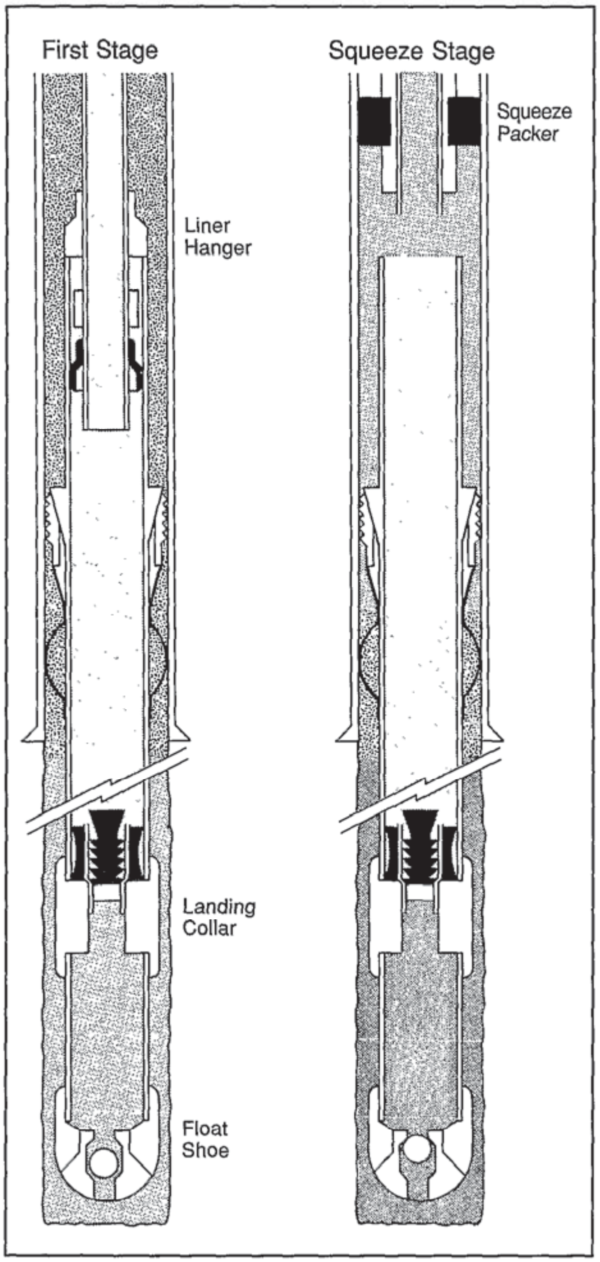

Figure 12–15—Liner cementing—planned squeeze.

12–4.2.3 Planned Squeeze

Long liners can be cemented in two stages when they traverse weak formations which would not withstand the hydrostatic pressure of a long column of cement. As illustrated in Fig. 12–15, the first stage is performed through the shoe using a limited, calculated amount of cement to cover the weak zone placing the cement top as close to the last casing shoe as possible. After the first stage is completed, the setting tool and drillpipe are pulled out of the hole, and the cement is allowed to cure. Drillpipe with a standard squeeze packer is then run into the hole, and the packer is set two or three joints above the liner hanger. The second stage is then performed by squeezing a premixed amount of cement around the liner hanger. To be able to squeeze cement into the annular space, the formation fracture pressure in the openhole section must be overcome.

The advantages of the method are—

- avoids damaging weak productive formations,
- uncontaminated cement is placed at the liner hanger, and
- no excess cement is necessary.

Disadvantages include—

- the complete annular space may not be cemented, and
- the technique is more expensive.

With the advent of ultralow-density microsphere and foamed cement systems, this procedure is obsolete.

12–4.2.4 Waiting-on-cement (WOC) for Liners

When long liners are to be set, there may be a considerable temperature differential between the bottom and top of the liner. A slurry designed to have sufficient thickening time at the total depth may take a very long time to set at the liner top. Drilling of cement must be done after the cement develops the minimum compressive strength to withstand the shock caused by drilling tools.

12–4.2.5 Tieback Liners

There are situations when it may be necessary to extend an existing liner further uphole, with a tieback "stub" liner, or to surface with a tieback casing string. Some of the reasons for running tieback stub liners or tieback casing are—

- to cover up damaged casing above the top of an existing liner,
- the need for a bigger casing on top of the existing liner to allow for multiple production strings,
- selective testing of multiple zones to design future production assemblies and production casing size, and
- cementing of troublesome intervals (high pressure, sloughing shales, etc.) before running the casing string to surface.

To accomplish this, special tools to connect the two liner strings must be used.

Tieback Sleeve—Installed on top of the liner hanger, the tieback sleeve provides a receptacle for the sealing nipple. Its internal surface is usually polished and beveled on the top to guide the entry of the different tools used during the operation.

Tieback Sealing Nipple—Run at the bottom of the tieback stub liner or casing, the tieback sealing nipple has multiple packing elements which provide a seal against the polished surface of the tieback sleeve.

Tieback casings are usually cemented by conventionally circulating the slurries. The job is performed before landing the seal nipple into the tieback sleeve. However, the cementing may also be conducted with the tieback casing in place, using a stage collar located above the sealing nipple.

Tieback liners must be cemented after their liner hangers have been set, and with the seal nipple landed into the sleeve (Fig. 12–16). A stage collar can be run on top of the seal nipple, in the open position. The liner wiper plug must be able to land on the upper seal and close the collar ports.

Apart from the special procedures given above, the considerations applicable to all cement jobs equally apply to tieback liner cementing. In most cases, hydrostatic pressures are not significant because cementing is done between casings and usually with extended slurries.

The use of washes ahead of cement slurries will prevent mud/cement contamination and help to remove the mud from the annular space. This is especially important in tieback liner cementing, where no bottom plug is used to separate the mud from cement inside the liner. If a completion fluid is in the hole, compatibility with the cement must be checked or large volumes of fresh water be pumped ahead of the slurry. Salts used in completion brines may drastically affect a cement slurry's thickening time, causing a premature set or, conversely, resulting in excessively long times for the development of early compressive strength.

12–5 SPECIAL OFFSHORE TECHNIQUES

As discussed in Chapter 10, the logistics of offshore cementing operations can be much different from those for land-based operations, but the cementing procedure employed on offshore drilling rigs or platforms fixed to the seabed is very similar to primary cementing operations on land. However, considerable differences exist in the plug release technique from floating drilling vessels, and where there are subsea completions.

Figure 12–17 illustrates the system, which consists of a special subsea assembly located in the casing below the casing hanger, and the cementing head on the floating drilling vessel which is screwed onto the drillpipe and controls the cementing plug release. The head contains a launching ball and dart, while the subsea assembly contains the top and bottom casing plugs. Referring to Fig. 12–17, and by chronological order of usage, (b) is the bottom plug launching ball which, when released before pumping the cement slurry, seats in the bottom plug (e). A 100- to 275-psi (0.7- to 1.9-MPa) pressure increase allows the connector pins to be sheared (d), and permits the bottom plug (e) to travel down the casing until it bumps on the float collar and casing shoe.

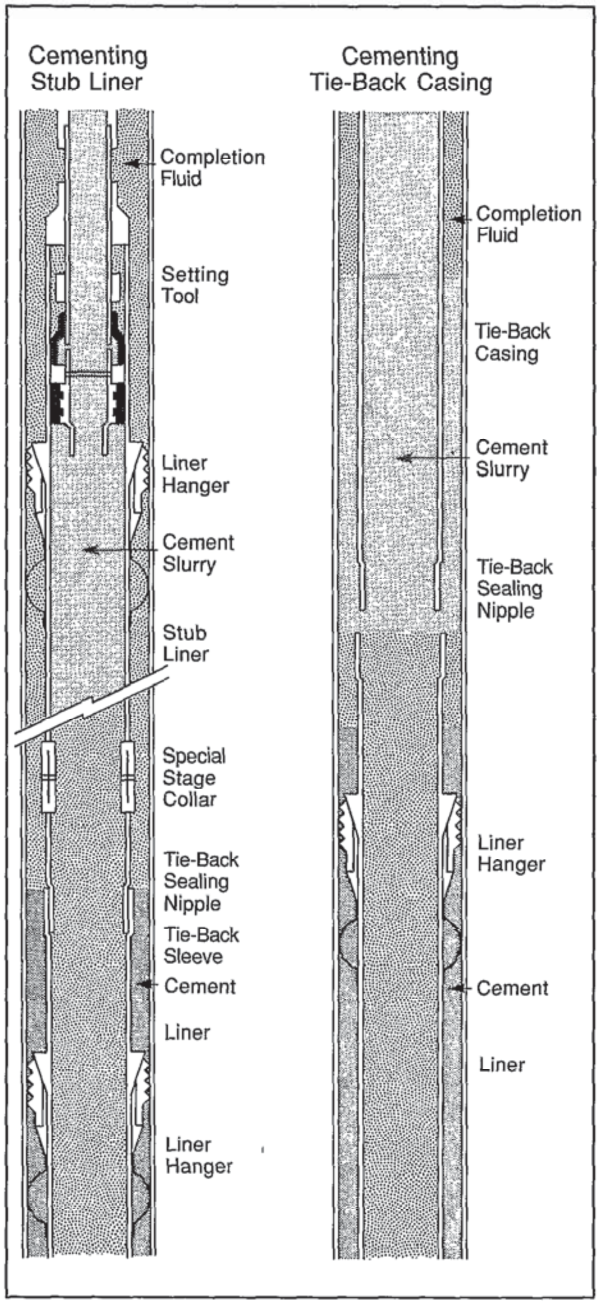

Figure 12–16—Tieback liner cementing.

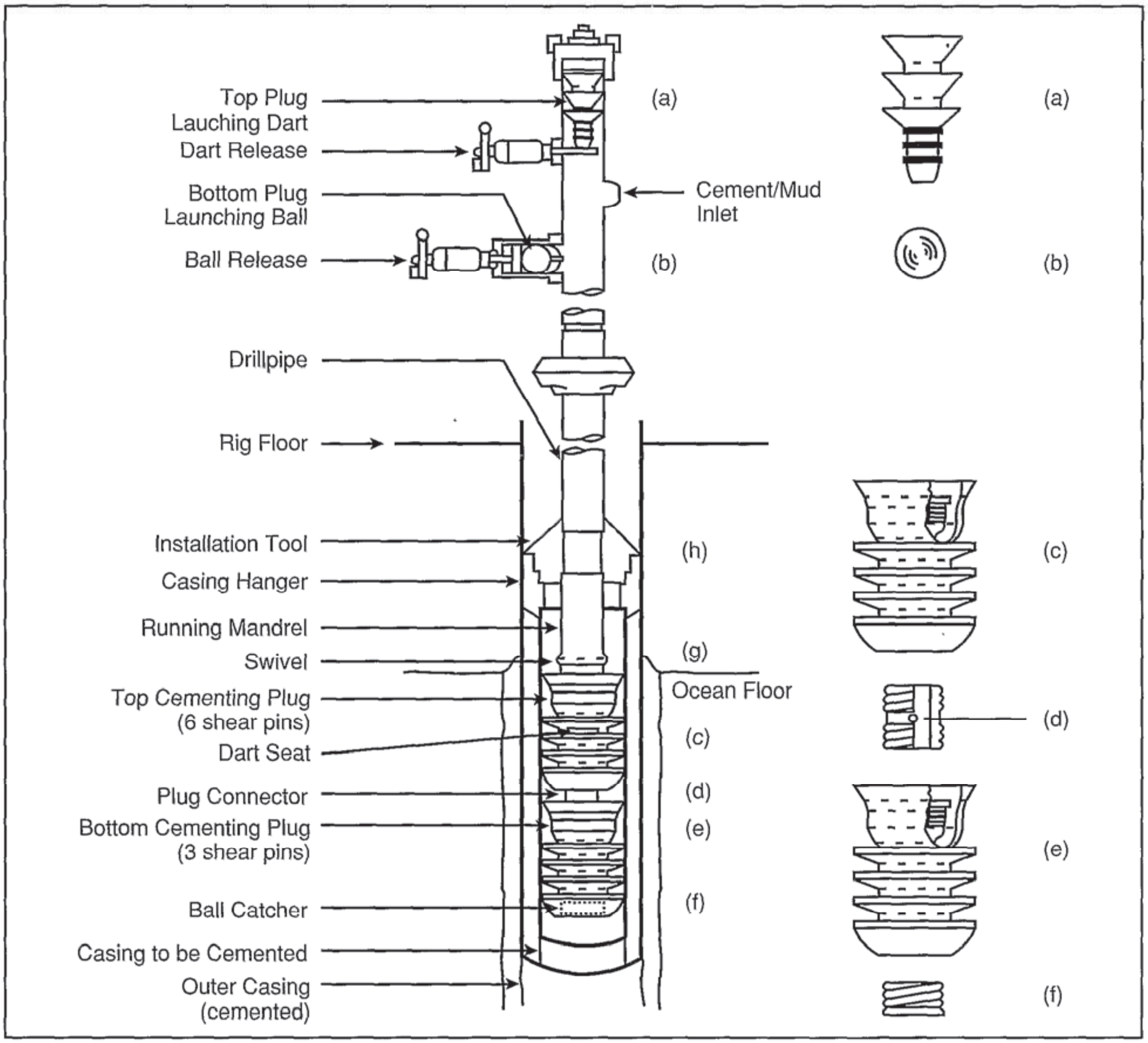

Figure 12–17—Single-stage subsea cementing system.

Extra pump or hydrostatic pressure extrudes the ball (b) through its orifice seat, and cement displacement continues. A ball catcher attached to the lower end of the bottomhole plug retains the ball.

Once the cement slurry has been pumped, the top plug launching dart (a) is released. It will seat into the body of the top cement plug (c). Increased circulation pressure will then shear the retaining pins and release the top plug (c) from the launching mandrel. The cementing operation thus continues. At the end of the slurry displacement, the top plug (c) bumps on the float collar or casing shoe.

In the subsea assembly before cementing, the top plug is pinned at the lower end of a running mandrel which has a swivel (g). This avoids any rotation of the cementing plugs inside the casing, which could damage the shear pins. The upper part of the mandrel is screwed onto the lower part of the installation tool (h). This installation tool is a crossover that adapts to the casing hanger, and serves to attach it to the drillpipe. One of the major limitations, and often a source of cementing failure, is the reduced flow area through the plug-retaining mandrel. This restricted flow area is susceptible to fluid erosion and failure due to high pump rates (often required for turbulent flow) and large fluid volumes of either mud or cement.

Other significant points to consider in subsea cementing are hydrostatic pressures and temperature. The additional column of fluid equal to the water depth can be a significant factor, as is the temperature at the sea bottom and the first several hundred meters of hole.

In addition to these, a complete understanding of the subsea wellbore geometry is necessary to assure full well control during the entire cementing operation. Figure 12–18 illustrates the general arrangement of the subsea BOP system.

12–6 OPERATIONAL CONSIDERATIONS

Planning is basic to successful primary cementing. It begins with accurate knowledge of the well conditions. The cement job is designed for these conditions, and job parameters must be monitored and recorded during job execution, so that the actual job can be compared to the design.

12–6.1 Calculations

Because of the difficulty of calipering large open holes, surface casing hole volumes are rarely known. The volume of cement slurry then has to be based on common field practice in the area. If this is not known, excess slurry volumes of 50% to 100% should be used. Excess slurry volumes of up to 200% are common in some areas.

Even when a caliper is run, and the theoretical volume is calculated, an excess volume is often required to assure proper fill-up. Local experience may dictate the excess cement required. Up to 50% in excess of the calipered hole volume may be used. In many countries, the volumes of slurries are governed by regulations which can be very comprehensive (Chapter 11).

12–6.2 Hole Condition

In addition to the physical parameters of the hole (i.e., depth, diameter, direction, etc.), the drilling log should be reviewed to identify potential problems which would affect the cement job. Hole washouts, lost circulation, tight spots, etc., all should be noted and compensated for in the design. A caliper log should be mandatory on most jobs. Drilling mud type and properties have a significant effect on hole condition, conditioning the hole prior to the cement job, and the cement slurry. Drilling muds must be designed for good primary cement jobs. If this is not always possible, then intermediate muds should be mixed specifically to satisfy cementing requirements.

12–6.3 Temperature

Knowledge of the bottomhole circulating temperature (BHCT) is vital. The cement slurry pumping time is a direct function of the hole temperature. Extended slurry pumping times can be as disastrous to primary cementing as can too short a time. Temperature also affects the cement and mud rheology; consequently, the flow regimes, U-tube effect, and friction pressures are all directly affected (Chapters 4 and 5). The BHCT must be determined if unknown. This can be done through logging, circulating temperature probes (Jones, 1986), or mathematical simulation of circulating temperature (Beirute, 1988; Mitchell and Wedelich III, 1989).

12–6.4 Pressure

Accurate knowledge of downhole pressure is necessary for well control and successful primary cementing. Slurry density is required for well control and set cement strength. Too high a density will lead to fractured formations and lost circulation. A typical intermediate casing string cement job, and the minimum and maximum hydrostatic pressures, are shown in Fig. 12–19. This type of plot should be generated for all primary cement jobs (Chapter 11).

12–6.5 Quality Control

A definite quality control program should be employed to test all materials prior to cementing. Laboratory conditions should closely simulate the job as is possible from known well conditions. Actual field batch samples of cement, additives, and mix water should be used for testing.

As API specifications for cements are necessarily broad in scope, additional testing should be performed whenever consistent quality of the cement is suspect. API rheology tests may help to identify potential problems. Liquid additives should also be checked and thoroughly blended with the mix water prior to cementing. Certain dry additives are prone to separation (particularly weighting agents), and care should be taken to verify that proper blending with the dry cement exists prior to the job (Gerke et al., 1985).

12–6.6 Casing Movement

As stated in the Amoco cementing guidelines (Smith, 1982), "The best aid to moving casing is the will to do it." Casing movement, reciprocation, rotation, or all three, positively improves the quality of primary cement jobs (Fig. 12–20). Casing movement breaks up areas of stagnant mud which can cause cement channeling. Scratchers and wipers are of little benefit, unless they are put to work by casing movement.

Casing, once landed, which cannot be moved prior to cementing, is a positive indication that something is wrong. Often, not much can be done at this point other than to cement the casing in place; however, the chances of a successful cement job are diminished before even mixing the slurry.

12–6.7 Cement Job Monitoring

The recording of critical parameters during cementing is paramount. Accurate knowledge of pressure, slurry rate,

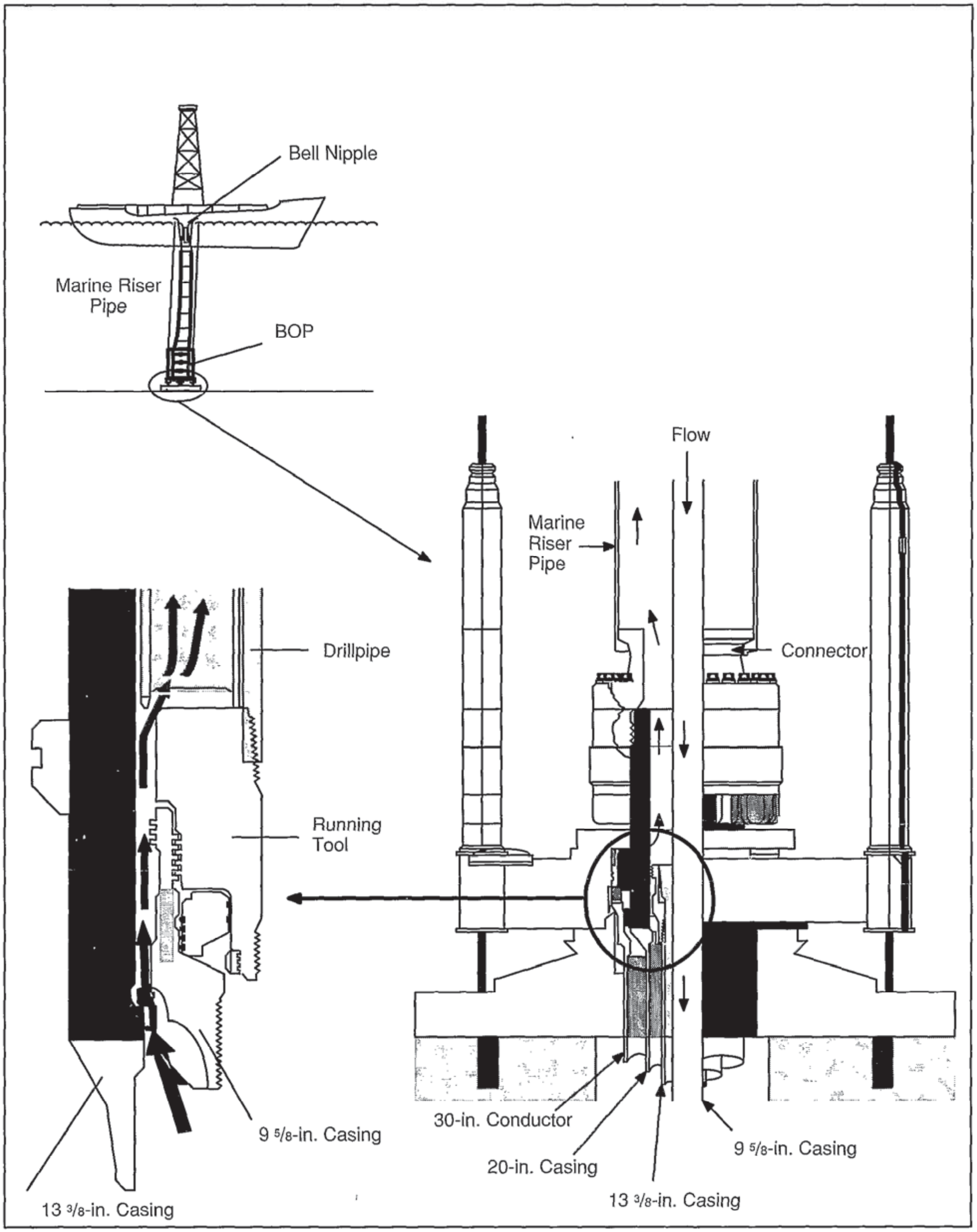

Figure 12–18—Wellbore geometry with a floating drilling vessel.

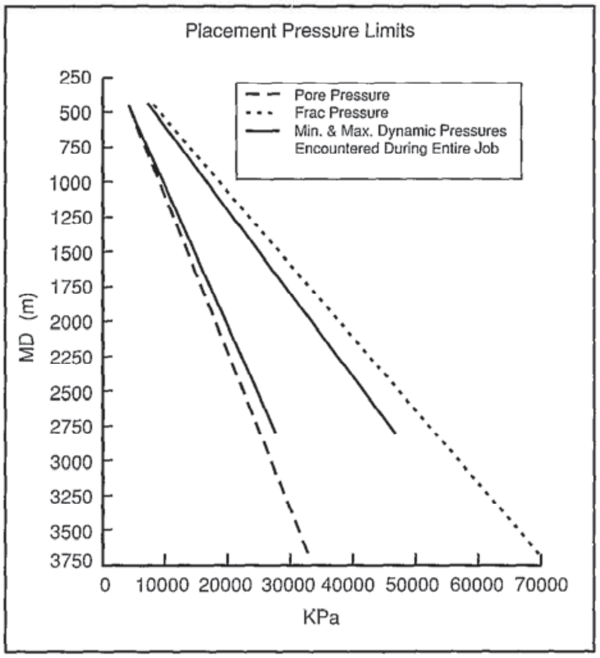

Figure 12–19—Pressure plot for intermediate casing string cement job.

and density, along with the integrated volume, are factors that must be known to the cementer and operating company representative in real time. These data should also be recorded so that future playback and analysis are possible, to evaluate and optimize the design of future jobs.

A typical recording device output is shown in Fig. 12–21. The recording of the vital parameters has greatly improved the success of primary cementing. All operations on the job are recorded, and subsequent review can be performed to evaluate the primary job, and compare the actual job to that designed. Recording devices also verify that the correct volumes and densities of preflushes, spacers, and cement slurry were pumped into the well.

The sensor package is equally important. Pressure is more routinely monitored with more accurate and faster responding electronic transducers replacing the traditional hydraulic gauges. Flowmeters working on an electromagnetic principle have been recently introduced, and are capable of measuring nonconductive oil-base fluids as well as conductive aqueous systems. Currently, most flow measurements are obtained from the drive shafts of

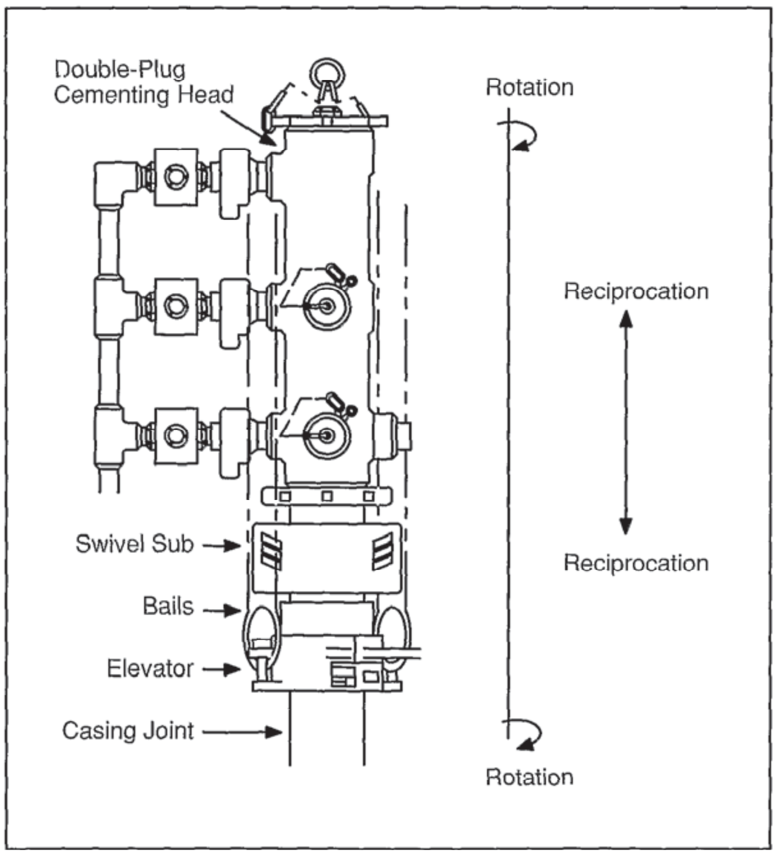

Figure 12–20—Rotating and reciprocating casing during cementing.

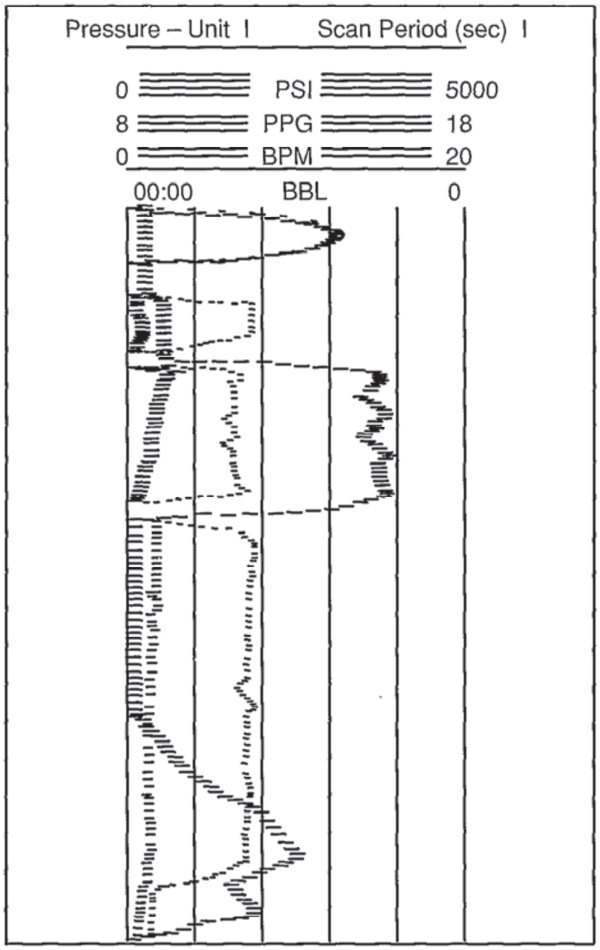

Figure 12–21—Recording device output for cement jobs.

the positive displacement pumps, or by counting the reciprocation of the pump plungers. The densities of the fluids are more accurately recorded with fully enclosed radioactive densitometers.

12–6.8 Casing Connections and Completions

When the conductor pipe has been driven to the desired depth, a mud return line or flowline is welded underneath the rig floor so that mud can return to the pits. The hole is then drilled to the depth required for the surface casing. After it has been run and cemented (always to surface), it is cut off underneath the rig floor at the desired height. The casing head (which will enable the next size of casing to be hung) is then welded to the surface casing, inside and outside. Some are available which screw onto a casing thread.

The BOPs with the connections for the kill line and choke line are flanged onto the casing head. Only one annular preventer may be attached, at this point, or a full set including blind rams and pipe rams. Before drilling can continue, the BOPs must be tested to the desired pressure. A sealing plug is run into the casing on drillpipe, and the BOPs are closed one by one. Pressure is then applied through the kill line.

All the BOPs and the wellhead connections must hold pressure before drilling can continue (Fig. 12–22). Then, when the next size of hole has been drilled to the desired depth, the next size of casing is run in and cemented. Cement may or may not be required to reach the surface.

The cement is usually allowed to set up while the casing is hanging from the elevators. After it has set, while the casing is still hung from the elevators, the BOPs are unscrewed from the casing head and suspended from the substructure. Slips are then set between the casing and the casing head.

It is very important that the casing be set with the same weight hanging from the slips that were taken by the elevator, to avoid buckling of the casing downhole. The casing can then be cut off either level with the casinghead flange or one or two feet higher. A sealing mechanism is normally placed above the slips to seal the annulus between the two casing strings. Then a new casing head is flanged to the previous head, the BOPs are reattached (or replaced by BOPs with a higher pressure rating), and (after testing) drilling can recommence. This entire process is known as "nippling up."

In this way, each time a new string of casing is run, it is hung from a casing head that was attached to the previous casing head. The production casing will have a head from which to hang the tubing—the tubing head. Therefore,

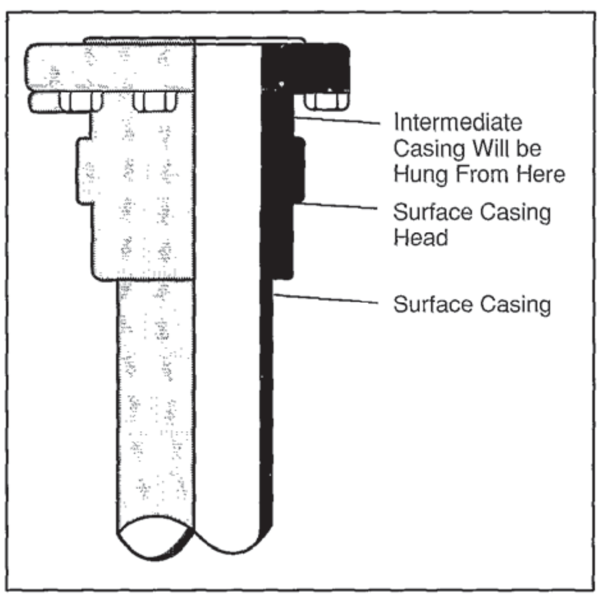

Figure 12–22—Connection of casing strings.

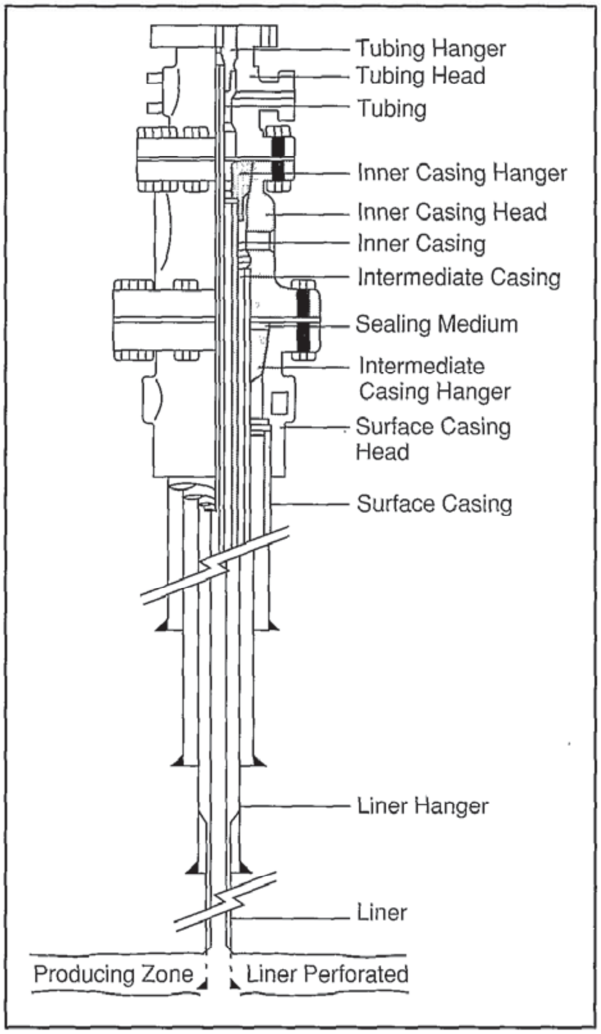

Figure 12–23—Typical wellhead assembly on a production well.

the weight of all the strings is partly supported by the surface casing (Fig. 12–23).

12–7 CONCLUSIONS

The basic mechanics of the more common primary cementing techniques has been presented in this chapter. When decoupled from the other related issues, such as fluid rheology, cement slurry design, cement slurry mixing procedures, annular gas migration, etc., these procedures may appear to be very simple. Such an impression is deceptive. It is essential that the engineer be intimately familiar with the procedures and devices which are used for primary cementing. In addition, it is critical that the engineer verify that all equipment is in proper working order before the job; otherwise, the long and meticulous planning process before each job may be wasted.

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13

Remedial Cementing

Christian Marca

Schlumberger Dowell

13–1 SQUEEZE CEMENTING—INTRODUCTION

Squeeze cementing has long been a common operation. Numerous squeeze jobs are performed daily under a wide variety of downhole conditions, and considerable experience has been accumulated over five decades of field practice. Although excellent literature describing this technology has been published and is readily available, misconceptions still exist and operating failures are not uncommon, resulting in increased drilling and completion costs. This chapter presents a review of squeeze cementing technology, with the aim of contributing to improvements in the design and execution of such treatments. The relevant equations which are useful for job design are found in Appendix C.

Squeeze cementing is defined as the process of forcing a cement slurry, under pressure, through holes or splits in the casing/wellbore annular space. When the slurry is forced against a permeable formation, the solid particles filter out on the formation face as the aqueous phase (cement filtrate) enters the formation matrix. A properly designed squeeze job causes the resulting cement filter cake to fill the opening(s) between the formation and the casing. Upon curing, the cake forms a nearly impenetrable solid (Suman and Ellis, 1977). In cases where the slurry is placed into a fractured interval, the cement solids must develop a filter cake on the fracture face and/or bridge the fracture.

Squeeze cementing has many applications during both the drilling and the completion phases. The most commonly cited applications are listed below.

- Repair a primary cement job that failed due to the cement bypassing the mud (channeling) or insufficient cement height in the annulus.
- Eliminate water intrusion from above, below, or within the hydrocarbon producing zone.
- Reduce the producing gas/oil ratio (GOR) by isolating the gas zones from adjacent oil intervals.
- Repair casing leaks due to corroded or split pipe.
- Abandon a nonproductive or depleted zone.
- Plug all, or part, or one or more zones in a multizone injection well so as to direct the injection into the desired intervals.
- Seal off lost-circulation zones.
- Protect against fluid migration into a producing zone.

These scenarios are discussed later in the chapter. First, a review of squeeze cementing theory, placement techniques, and slurry design is presented.

13–2 SQUEEZE CEMENTING—THEORY

Regardless of the technique used during a squeeze job, the cement slurry (a suspension of solids) is subject to a differential pressure against a filter of permeable rock. The resulting physical phenomena are filtration, filter-cake deposition and, in some cases, fracturing of the formation. The slurry, subject to a differential pressure, loses part of its water to the porous medium, and a cake of partially dehydrated cement is formed.

The cement cake, forming against a permeable formation, has a high initial permeability (Fig. 13–1). As the particles of cement accumulate, the cake thickness and hydraulic resistance increase; as a result, the filtration rate decreases, and the pressure required to dehydrate the cement slurry further increases. The rate of filter-cake buildup is a function of four parameters:

- permeability of the formation,
- differential pressure applied,
- time, and
- capacity of the slurry to lose fluid at downhole conditions.

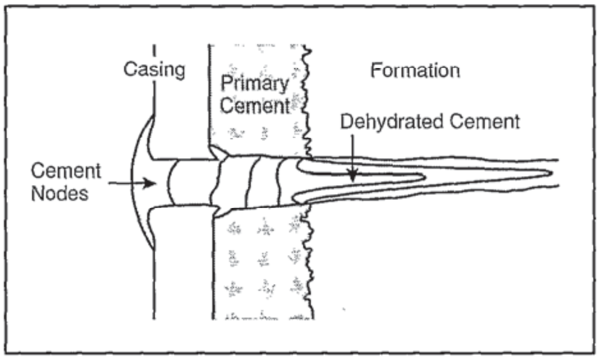


Figure 13–1—Cake permeability and dehydration rate of a slurry as a function of the fluid loss additive concentration (after Hook and Ernst, 1969).

When squeezed against a formation of given permeability, the rate at which slurry dehydration decreases is directly related to the fluid-loss rate (Fig. 13–2). When squeezed against low-permeability formations, slurries with low fluid-loss rates dehydrate slowly, and the duration of the operation may be excessive. Against a high-permeability formation, a slurry with a high fluid-loss rate dehydrates rapidly; consequently, the wellbore may become choked by filter cake, and channels which otherwise would have accepted cement would be bridged off. The ideal squeeze slurry should thus be tailored to control the rate of cake growth, and allow a uniform filter cake to build up over all permeable surfaces.

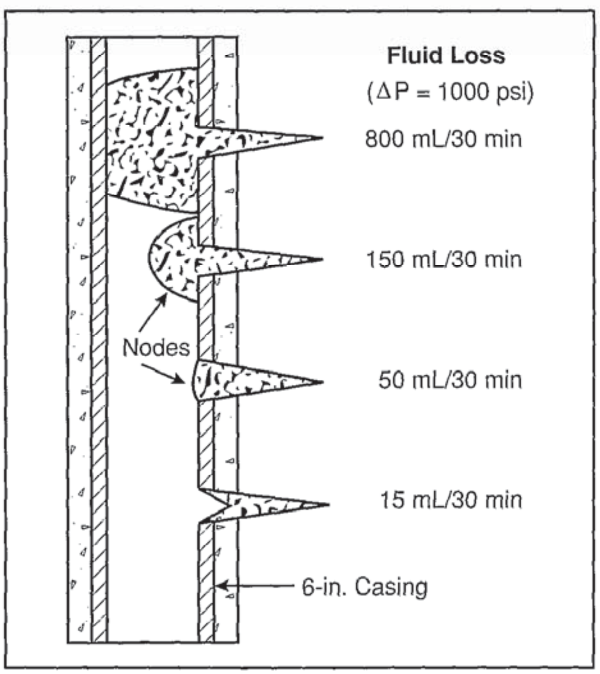


Figure 13–2—Node buildup after a 45-minute squeeze using slurries with different water loss (after Rike, 1973).

The basics of the theoretical and practical work regarding the fundamentals of filter-cake deposition in squeeze cementing can be found in the publications of Binkley, Dumbauld, and Collins (1958) and Hook and Ernst (1969).

13–2.1 Binkley, Dumbauld, and Collins Study

These authors developed the law of filter-cake formation for a suspension (such as a cement slurry). When a volume dQ of filtrate passes through a planar permeable surface of area A, a filter cake of thickness dS and of porosity ϕ is deposited. This relationship is illustrated in the following series of equations.

$$dS = \frac{f}{1 - f - \phi} \times \frac{dQ}{A}, \qquad (13\text{–}1)$$

where

f = fraction by volume of solids in the suspension, or

$$f = \frac{V_{solid}}{V_{solid} + V_{liquid}}. \qquad (13\text{–}2)$$

The ratio $w = f/(1-f-\phi)$ is called the "deposition constant."

The "law of filter-cake formation" may thus be written as

$$\frac{dS}{dt} = wq, \qquad (13\text{–}3)$$

where

q = flow rate of filtrate per unit area of surface, and
dS/dt = rate of growth of the filter-cake thickness.

Assuming that the pressure drop across the filtration surface is negligible, Binkley et al. (1958) applied Darcy's law to the flow of the filtrate through the cake, establishing the following equations.

1. *Growth of a filter cake as a function of filtration time.*

$$S = \sqrt{\frac{2kw\,\Delta P}{\mu}}\; t^{1/2}, \qquad (13\text{–}4)$$

where
k = permeability of the filter cake (constant),
μ = viscosity of the filtrate, and
ΔP = differential pressure.

2. *Cumulative volume of filtrate as a function of filtration time.*

$$Q = \sqrt{\frac{2kA^2\Delta P}{\mu w}}\; t^{1/2} \qquad (13\text{–}5)$$

3. *Filter-cake permeability.*

$$k = \frac{\mu Q S}{2 A t \Delta P} \qquad (13\text{–}6)$$

4. *Deposition constant.*

$$W = \frac{AS}{Q} \qquad (13\text{–}7)$$

5. *Fill up of an unfractured perforation.*

Binkley et al. (1958) assumed the perforation geometry shown in Fig. 13–3. The depth of the perforation is considered large in relation to its diameter (at least four times greater). Assuming that the pressure drop in the formation is zero, Binkley et al. (1958) demonstrated that the time required to build a filter cake in close contact with the inside of the casing can be expressed with the following equation.

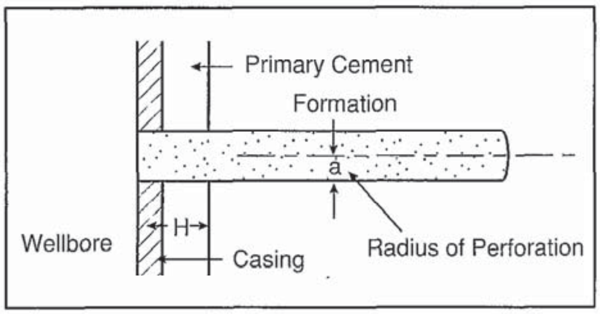


Figure 13–3—Geometry of perforation (after Binkley, Dumbauld, and Collins, 1958).

$$T = \frac{\mu}{k w \Delta P}\left(\frac{H^2}{2} + \frac{a^2}{4} + e\,aH\right) \qquad (13\text{–}8)$$

Experiments determined e to be equal to 0.25. The ratio $\mu/kw\Delta P$ contains all the variables related to the deposition properties of the cement slurry, and is called the composition factor. It is interesting to note that, with the assumption regarding perforation depth vs its diameter, the depth of the perforation has a negligible effect on the deposition process.

By measuring the filter-cake thickness S and the cumulative volume of filtrate Q obtained when a cement slurry is in contact with a planar permeable surface of area A, and submitted to a differential pressure ΔP for a time T, it is possible to determine the filter-cake permeability k and the deposition constant w.

6. *Deposition of solids inside the casing following perforation fill-up.*

To simplify the calculation, Binkley et al. (1958) assumed that the node building up inside the casing has a spherical shape at every stage of the growth, and that the lateral growth occurs at the same rate as the vertical growth. The geometry is illustrated in Fig. 13–4. If h is the height of the node building up inside the casing, then the equation below can be derived.

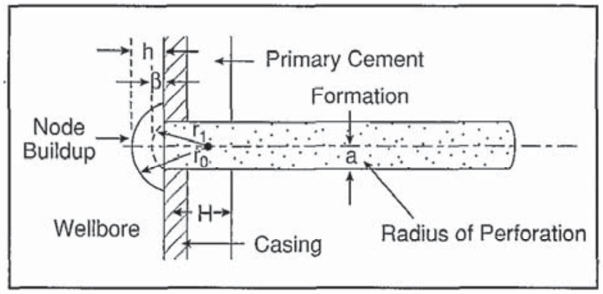


Figure 13–4—Geometry of the cement node (after Binkley, Dumbauld, and Collins, 1958).

$$\frac{dh}{dt} = \frac{k w \Delta P}{\mu}\left[\frac{1}{(H + \beta + ea)\frac{r_0^2}{r_1^2} + \frac{r_0^2}{r_1^2} - r_0}\right], \qquad (13\text{–}9)$$

where

H = combined thickness of the cement sheath and casing,

a = radius of the perforation,

$$\beta = r_1 - \sqrt{r_1^2 - a^2},$$

$$r_0 = \frac{h^2 + (a + h)^2}{2h}$$

$$r_1 = \sqrt{(r_0 - h)^2 + a^2}, \text{ and}$$

$$e = 0.25.$$

The results of the numerical integration of this complex equation have been plotted in Fig. 13–5, which represents the time required to fill a perforation and build a node, vs the ratio H/a, for different node heights.

13–2.2 Hook and Ernst Study

Hook and Ernst (1969) performed an experimental study of the effects of fluid-loss control additives, differential pressure, and formation permeability upon the rate of filter-cake buildup. Their conclusions are presented in Tables 13–1, 13–2, and 13–3.

Table 13–1 is a compilation of permeability measurements conducted on filter cakes which were formed with different concentrations of a fluid-loss additive. The permeability of a neat-cement filter cake was measured to be about 5 md—a value lower than that of many producing

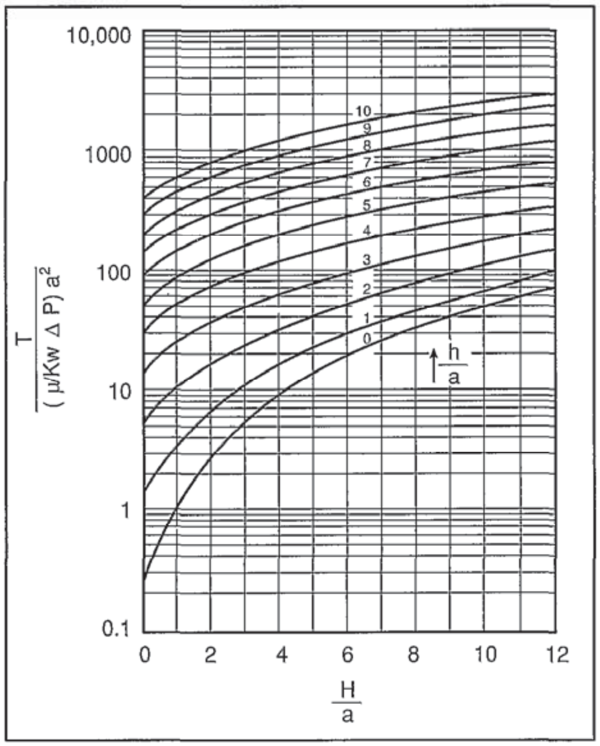


Figure 13–5—Relationship between slurry property, perforation geometry, and height of filter-cake node inside casing (after Binkley, Dumbauld, and Collins, 1958).

Slurry — API Class A Cement with Liquid Fluid-Loss Additive and 46% Water			
Concentration of Fluid-Loss Additive (gal/sk)	**API Fluid Loss at 1000 psi (cc/30 min)**	**Permeability of the Filter Cake Formed at 1000 psi (md)**	**Time to Form a 2-in. Thick Filter Cake (min)**
0.00	1200	5.00	0.2
0.07	600	1.60	0.8
0.13	300	0.54	3.4
0.17	150	0.19	14.0
0.19	100	0.09	30.0
0.22	50	0.009	100.0
0.24	25	0.006	300.0

Table 13–1—Cake permeability and dehydration rate of a slurry as a function of the fluid-loss additive concentration (after Hook and Ernst, 1969).

sandstone formations. When the slurry contains sufficient fluid-loss additive to reduce the API fluid-loss rate to 25mL/30 min, the resulting filter cake is approximately 1,000 times less permeable. This approaches the permeability of matrix formations that produce very slowly, and are difficult in which to pump.

Table 13–1 also shows that the rate of filter-cake growth is indirectly related to the permeability of the filter cake. Fluid-loss additives lower the permeability of the filter cake; consequently, the quantity of solids which can be filtered out from the slurry is also reduced.

The data in Table 13–2 demonstrate the influence of squeeze pressure upon the rate of filter-cake growth. First, it was shown that varying the squeeze pressure from 500 to 1,000 psi (3.5 to 6.9 MPa) does not influence the permeability of the resulting filter cake. Nevertheless, in keeping with Darcy's law, the data showed that the flow rate of fluid through the filter cake was directly proportional to the squeeze pressure.

Differential of Filter Cake Formation (psi)	**Permeability of Filter Cake (md)**	**API Fluid Loss (cc/30 min)**	**Flow Rate Through Filter Cake (cc/min)**
Slurry I			
500	5.8	1200	50
1000	6.0	1200	110
Slurry II			
500	1.9	600	17
1000	1.6	600	30
Slurry III			
500	0.53	300	4.7
1000	0.54	300	9.7
Slurry I — Class A Cement 46% Water Slurry II — Class A Cement 0.5% Dispersant 0.07 gal/sk Liquid Fluid-Loss Additive 46% Water Slurry III — Class A Cement 0.5% Dispersant 0.13 gal/sk Liquid Fluid-Loss Additive 45% Water By increasing the pressure from 500 psi to 1000 psi, the filtration rate is increased by a factor close to 2.			

Table 13–2—Effect of the differential pressure on the permeability of filter cakes and on the filtration rate (experimental) (after Hook and Ernst, 1969).

Table 13–3 shows the effect of formation permeability upon the rate of cement filter-cake growth. Against a 30-md formation, the time required to form a filter cake of given thickness is roughly twice that observed against a formation with a 300-md permeability. These results demonstrate the importance of knowing the formation permeability before designing the slurry; this point is discussed later in the chapter.

13–3 SQUEEZE CEMENTING—PLACEMENT TECHNIQUES

Normally, the slurry injection is performed through casing perforations. There are two fundamentally different squeeze job classifications.

- *Low-pressure squeeze:* The bottomhole treating pressure is maintained below the formation fracturing pressure.
- *High-pressure squeeze:* The bottomhole treating pressure exceeds the formation fracturing pressure.

Within these two classes, there are two basic techniques (the Bradenhead squeeze and the squeeze tool technique) and two pumping methods (the running squeeze and the hesitation squeeze). Each of these classifications and techniques is explained in this section.

13–3.1 Low-Pressure Squeeze

The aim of this operation is to fill the perforation cavities and interconnected voids with dehydrated cement. The volume of cement is usually small, because no slurry is actually pumped into the formation. Precise control of hydrostatic pressure of the cement column is essential, because excessive pressure could result in formation breakdown.

The following calculations are given as an example. A 500-psi (3.5 MPa) safety factor is taken, and friction losses are assumed negligible as a result of the very low rates at which the job is performed. The maximum column of cement the formation can withstand, X, is determined by the following equation.

$$X = \frac{[(FGh) - 500] - (0.052\, h\, \rho_c)}{0.052(\rho_s - \rho_c)} \qquad (13\text{–}10)$$

Therefore, the maximum volume of cement slurry is calculated by the equation below.

$$V_{max} = XV_t \qquad (13\text{–}11)$$

where

h = perforations depth (ft),

X = length of cement column (ft),

ρ_s = slurry density (lb/gal),

ρ_c = completion fluid density (lb/gal),

FG = formation fracture gradient (psi/ft),

500 = safety factor (psi),

0.052 = conversion factor (lb/gal to psi/ft),

V_t = tubing volume per unit of length (ft^3/ft), and

k = distance from packer to perforations.

Example

Perforations to be squeezed off at 6,250 ft through 2½-in.- ID tubing inside 7-in. (30-lb/ft, 0.0325-ft^3/ft) casing. Packer to be set at 6,150 ft.

Estimated Fracture Gradient—0.7 psi/ft
Displacement Fluid—8.6 lb/gal brine
Cement Slurry—Class G + 0.2 gal/sk fluid-loss additive + 0.1 gal/sk dispersant

Time Required for the Formation of a 1¼-in. Long Filter Cake on a 1-in. Diameter Filtration Surface at 1000 psi			
	Bandera Sandstone 30 md	Berea Sandstone 300 md	API 325-mesh Screen
Slurry I	6 min	2.5 min	2.5 min
Slurry II	9 min	6.5 min	6.5 min
Slurry III	5 min	2.5 min	2.5 min

Slurry I — API Class A Cement
0.5% Dispersant
0.14 gal/sk Liquid Fluid-Loss Additive
46% Water

Slurry II — API Class A Cement
0.5% Dispersant
0.17 gal/sk Liquid Fluid-Loss Additive
46% Water

Slurry III — API Class A Cement
0.7% Solid Fluid-Loss Additive
46% Water

Table 13–3—Effect of formation permeability on the rate of the filter cake growth (after Hook and Ernst, 1969).

Density: 15.8 lb/gal
Yield: 1.15 ft³/sk

Using Eq. 13–10, the following is obtained.

$$X = \frac{[(0.7 \times 6{,}250) - 500] - (0.052 \times 6{,}250 \times 8.6)}{0.052(15.8 - 8.6)}$$
$$= 2{,}885 \text{ ft}$$

Therefore, using Eq. 13–11, $V_{max} = 2{,}885 \times 0.0325 = 93.75$ ft³. Or, in terms of sacks of cement, 80 sk.

In low-pressure squeezes, it is essential that perforations and channels be clear of mud or other solids. If the well has been producing, such openings may already be free of obstructions; however, for newly completed wells, it may be necessary to clean the perforations before performing the squeeze job (Section 13–9.2)

A properly designed slurry will leave only a small node of cement filter cake inside the casing. Improperly designed systems can result in excessive development of cement filter cake. This can result in a complete bridging of the inside of the casing, with loss of pressure transmission to the formation, and insufficient contact of the cement filter cake with the formation.

Review of the literature shows that, according to most authors, a low-pressure squeeze should be run whenever possible, and that this technique has the highest success rate (Rike and Rike, 1981; Goodwin, 1984; Bradford and Reiners, 1985). The low-pressure squeeze requires only a small amount of cement slurry, while the high-pressure technique usually involves a larger volume of slurry.

13–3.2 High-Pressure Squeeze

In some cases, a low-pressure squeeze of the perforations will not accomplish the objective of the job. The channels behind the casing might not be directly connected to the perforations. Small cracks or microannuli that may allow flow of gas do not allow the passage of a cement slurry. In such cases, these channels must be enlarged to accept a viscous solids-carrying fluid. In addition, many low-pressure operations cannot be performed if it is impossible to remove plugging fluids, or debris, from ahead of the cement slurry or inside the perforations.

Placement of the cement slurry behind the casing is accomplished by breaking down the formation at or close to the perforations (Fig. 13–6). Fluids ahead of the slurry are displaced in the fractures, allowing the slurry to fill the desired spaces. Further application of pressure dehydrates the slurry against the formation walls, leaving all channels (from fractures to perforations) filled with cement cake.

However, during a high-pressure squeeze, the location and orientation of the created fracture cannot be controlled. Sedimentary rocks usually have an inherently low tensile strength, and are held together primarily by the weight or the compressive forces of overlying formations. These cohesive forces act in all directions to hold the rock together, but do not have the same magnitude in all directions. When sufficient hydraulic pressure is applied against a formation, the rock fractures along the plane perpendicular to the direction of the least principal stress (Fig. 13–7). A horizontal fracture is created if the fracturing pressure is greater than the overburden pressure. A vertical fracture occurs if overburden pressure is greater (Roegiers, 1987).

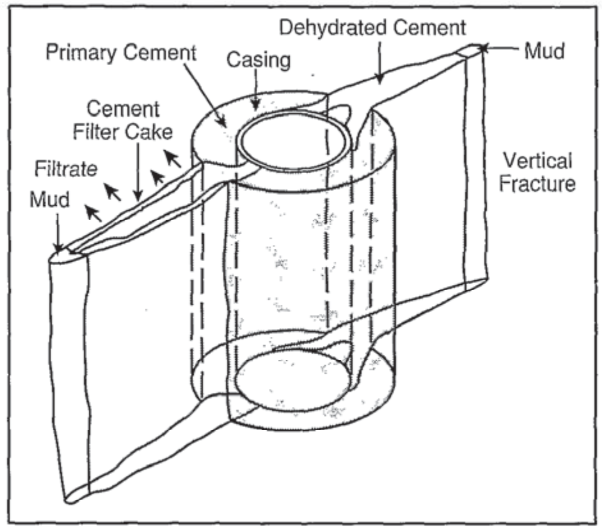


Figure 13–6—High-pressure technique: vertical fracture generated by high-pressure squeezing.

The extent of the induced fracture is a function of the pump rate applied after the fracture is initiated. The amount of slurry used depends on the way the operation is performed. High pump rates generate large fractures; thus, large volumes of cement are required to fill them. A properly performed, high-pressure squeeze should leave the cement as close to the wellbore as possible.

Drilling muds or other fluids with low fluid-loss rates should not be pumped ahead of the slurries. A wash with a high fluid-loss rate, such as water or a weak hydrochloric acid solution, not only opens smaller fractures but also cleans perforations and the cement path. The fracture initiation pressure is lower using this type of spearhead than using nonpenetrating fluids.

13–3.3 Bradenhead Placement Technique (No Packer)

This technique, illustrated in Fig. 13–8, is normally used when low-pressure squeezing is practiced, and when there are no doubts concerning the casing's capacity to withstand the squeeze pressure. No special tools are

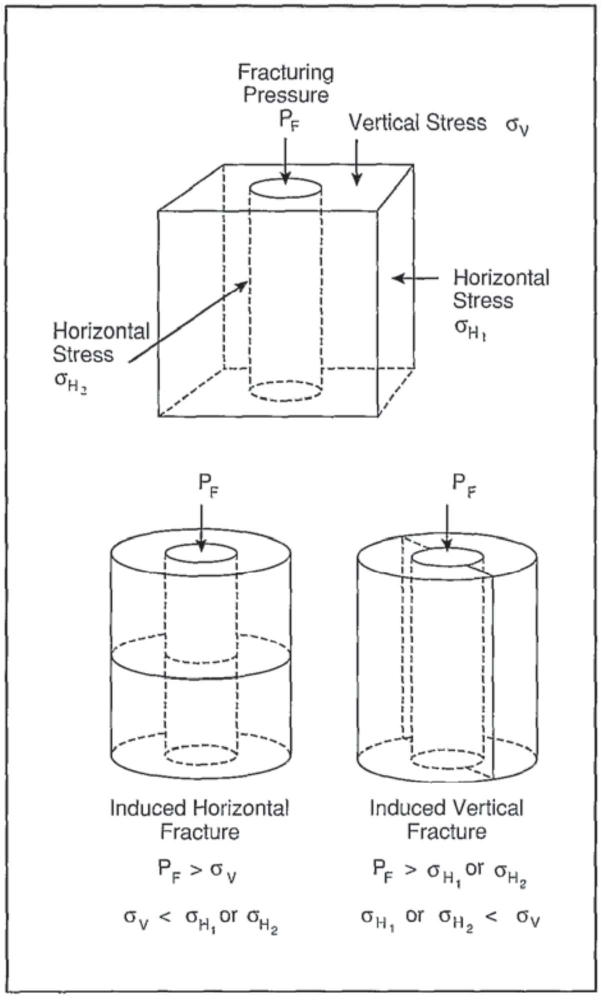


Figure 13–7—Effect of well depth and vertical/horizontal formation stresses on the orientation of hydraulic fracture induced by injected fluid. Horizontal fractures will not be created if fracture pressure is less than overburden pressure. This is usually the case at depths greater than 3,000 ft. (after Suman and Ellis, 1977).

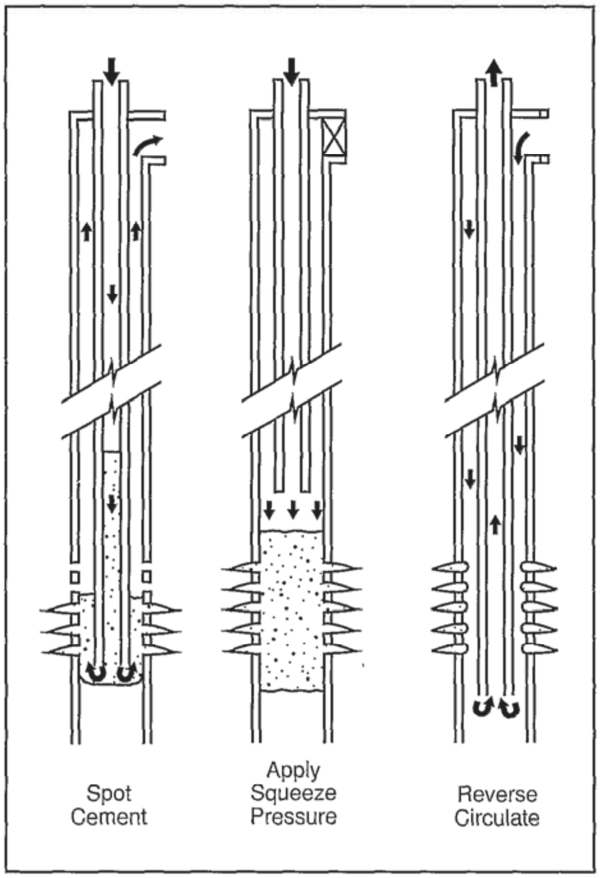


Figure 13–8—Bradenhead squeeze technique is normally used on low-pressure formations. Cement is circulated into place down drillpipe (left), then wellhead, or BOP, is closed (center) and squeeze pressure is applied. Reverse circulating (right) removes excess cement, or plug can be drilled out (after Suman and Ellis, 1977).

involved, although a bridge plug may be required to isolate other open perforations further downhole.

Open-ended tubing is run to the bottom of the zone to be cemented. Blowout preventer (BOP) rams are closed over the tubing, and the injection test is performed. The cement slurry is subsequently spotted in front of the perforations. Once the cement is in place, the tubing is pulled out to a point above the cement top, the BOPs are closed, and pressure is applied through the tubing. The Bradenhead squeeze is very popular because of its simplicity.

13–3.4 Squeeze Tool Placement Technique

This technique can be subdivided into two parts—the retrievable squeeze packer method, and the drillable cement retainer method. The main objective of using squeeze tools is to isolate the casing and wellhead while high pressure is applied downhole.

13–3.4.1 Retrievable Squeeze Packer Method

Retrievable packers with different design features are available (Chapter 10). Compression- or tension-set packers are used in squeeze cementing. As shown in Fig. 13–9, they have a bypass valve to allow the circulation of fluids while running in the hole, and once the packer is set. This feature allows the cleaning of the tools after the cement job, and the reversing out of excess slurry without excessive pressure; it also prevents a piston or swabbing effect while running in or out of the hole.

The principal advantage of the retrievable packer over the drillable retainer is its ability to set and release many times, thus allowing more flexibility. Retrievable bridge plugs can be run in one trip with the packer, and retrieved after the slurry has been reversed or drilled out. Most

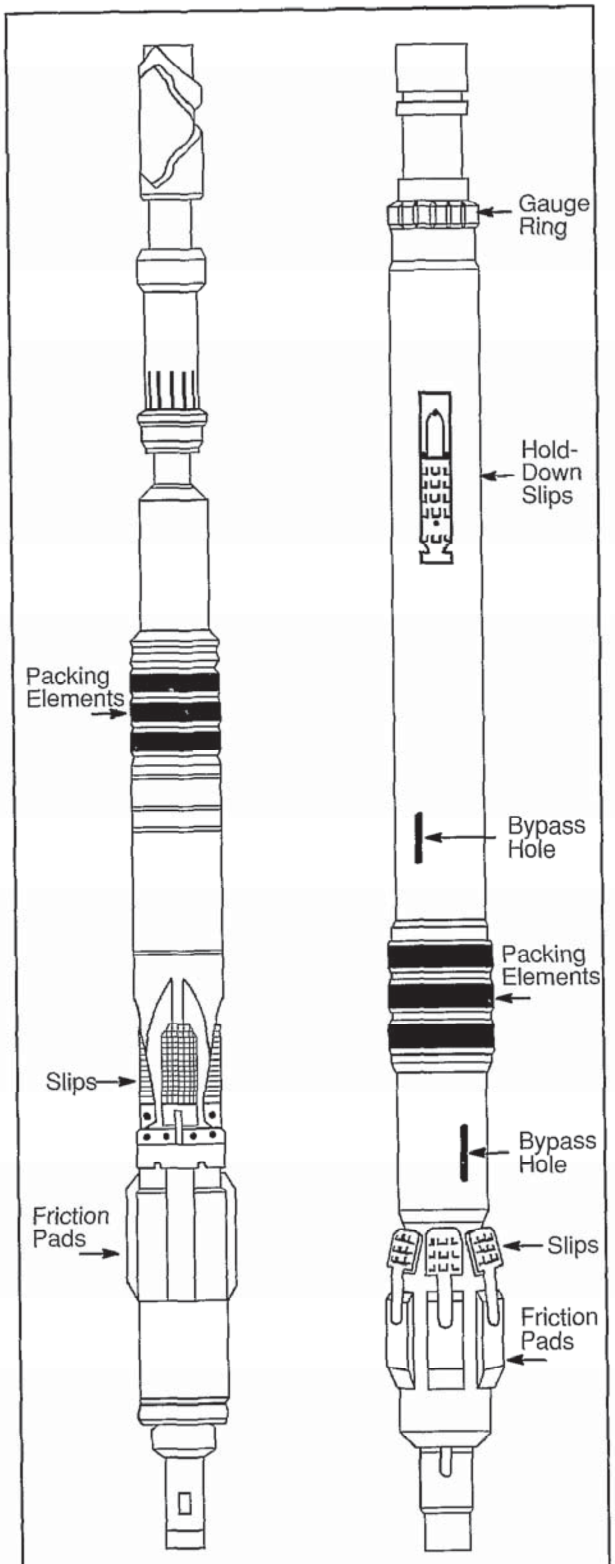


Figure 13–9—Bridge plug and squeeze packer.

operators drop one or two sacks of frac sand on top of the retrievable bridge plug before the job, to prevent the settling of cement over the releasing mechanism.

13–3.4.2 Drillable Cement Retainer

Cement retainers are used instead of packers to prevent backflow when no cement dehydration is expected, or when a high negative differential pressure may disturb the cement cake. In certain situations, potential communication with upper perforations makes the use of a packer a risky operation.

When cementing multiple zones, the cement retainer isolates the lower perforations, and subsequent zone squeezing can be performed without waiting for the slurry to set. Cement retainers are drillable packers provided with a valve which is operated by a stinger at the end of the work string (Fig. 13–10).

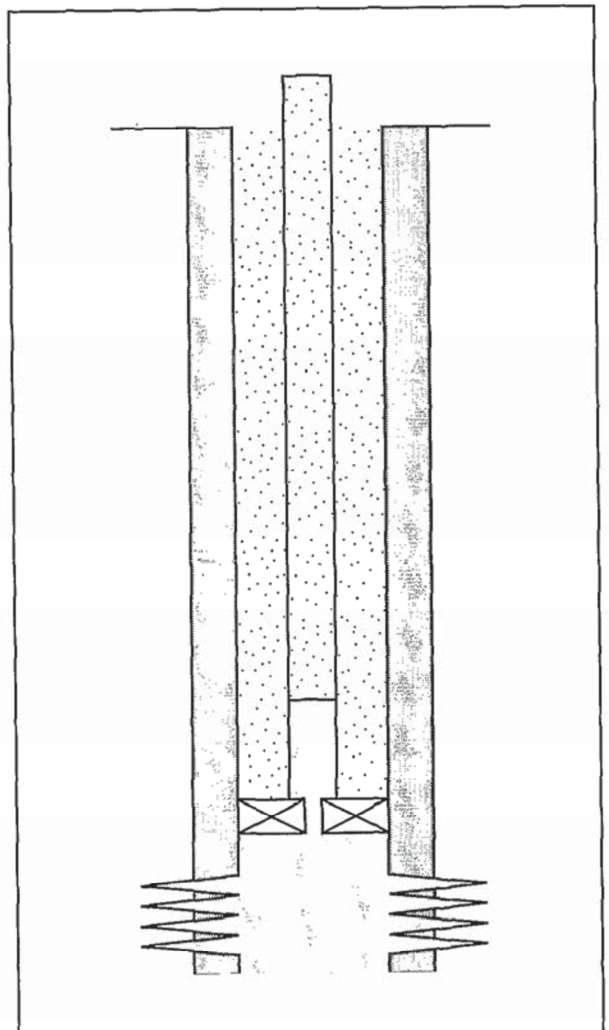


Figure 13–10—Squeeze with cement retainer.

A drillable retainer gives the operator more confidence in setting the packer closer to the perforations. This is also advantageous in that a lower volume of fluid below the packer is displaced through the perforations ahead of the cement slurry.

Drillable bridge plugs are normally used to isolate the casing below the zone to be treated. Their design is similar to that of cement retainers. They can be run with a wireline or with the work string. Bridge plugs do not allow flow through the tool.

13–3.5 Running Squeeze Pumping Method

During a running squeeze procedure, the cement slurry is pumped continuously until the final desired squeeze pressure (which may be above or below the fracture pressure) is attained. After pumping stops, the pressure is monitored and, if the pressure falls due to additional filtration at the cement/formation interface, more slurry is pumped to maintain the final surface squeeze pressure. This continues until the well maintains the squeeze pressure for several minutes without additional injection of cement slurry. The volume of slurry injected is usually large. Rike and Rike (1981) reported that volumes ranging from 10 to 100 barrels are commonly used.

13–3.6 Hesitation Squeeze Pumping Method

The relatively small amount of filtrate lost from the slurry makes impractical, if not impossible, continuous pumping at a rate slow enough to maintain a constant differential pressure. The minimum pump rate attainable with existing field equipment is excessive even for high-pressure squeezing where large fractures are created.

The only procedure which makes possible the dehydration of small quantities of cement into perforations of formation cavities is the hesitation squeeze pumping method. This procedure involves the intermittent application of pressure (at a rate of $^1/_4$ to $^1/_2$ bbl/min), separated by an interval of 10 to 20 minutes for pressure leakoff due to filtrate loss to the formation. The initial leakoff is normally fast because there is no filter cake. As the cake builds up, and the applied pressure increases, the filtration periods become longer and the difference between the initial and final pressures become smaller, until at the end of the job the pressure leakoff becomes negligible (Fig. 13–11). The volumes of slurry necessary for this technique are usually much less than those required for a running squeeze.

A loose formation normally requires a long hesitation period to begin building squeeze pressure. A first hesitation period of 30 minutes or more is not unreasonable. A much shorter initial hesitation period (possibly five minutes) is normally sufficient for tight formations (Grant and White, 1987).

13–4 INJECTION TEST

Prior to mixing and pumping the cement slurry, an "injection test" is performed. This procedure consists of pumping a fluid, typically water or a mud flush, into the well. The injection test is performed for several reasons:

- to ensure that the perforations are open and ready to accept fluids,
- to obtain an estimate of the proper cement slurry injection rate,
- to estimate the pressure at which the squeeze job will be performed, and
- to estimate the amount of slurry to be used.

Should the fluid fail to achieve the injection, acid should be injected under matrix conditions. Hydrochloric and hydrofluoric acids are commonly used.

13–5 DESIGN AND PREPARATION OF THE SLURRY

As discussed above, the properties of the cement slurry must be tailored according to the characteristics of the formation to be squeezed, and the technique to be used. It is generally agreed that a squeeze slurry should be designed to have the following general attributes:

- low viscosity—to allow the slurry to penetrate the small cracks,
- low gel strength—a gelling system restricts slurry movements and causes increases in surface pressure which are difficult to interpret,

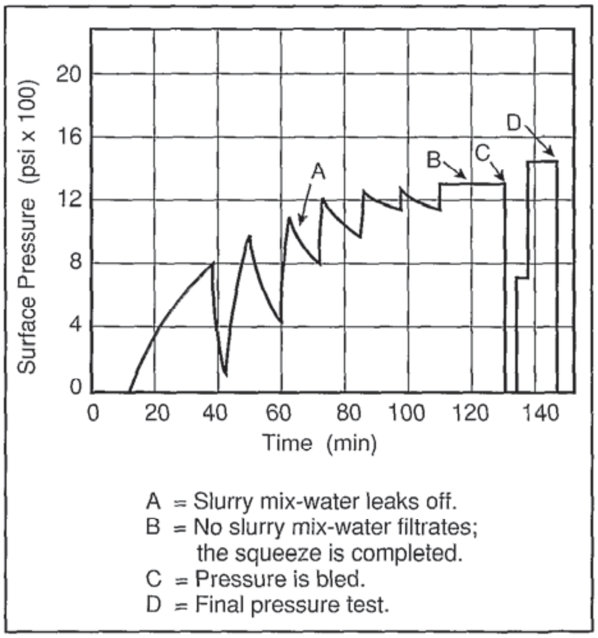


Figure 13–11—Hesitation squeeze pressure behavior.

- no free water,
- appropriate fluid-loss control—to assure optimum filling of the cracks or perforations, and
- proper thickening time—to safely meet the anticipated job time.

The specifications to test a squeeze slurry are found in API Spec 10 (1988) (Appendix B).

13–5.1 Fluid-Loss Control

As discussed earlier, fluid-loss control is particularly important when squeeze cementing across permeable formations. For low-pressure squeezing, a properly designed slurry should allow the complete filling of perforation cavities, leaving a minimum node buildup in the casing. The slurry fluid loss must be tailored to the formation type and the permeability (Young, 1967). The generally accepted API fluid-loss rates are listed below.

- Extremely Low-Permeability Formation: 200 mL/30 min
- Low-Permeability Formation: 100 to 200 mL/30 min
- High-Permeability Formation (>100 md): 35 to 100 mL/30 min

When squeezing fractured limestone or dolomite formations, the situation is different from that for sandstone, because the permeability consists of interconnected voids or fracture systems. All cement particles can enter these channels and, as the slurry slowly dehydrates, it will travel relatively long distances into the formation. Allowing this to happen may put the cement-free zone out of reach of the perforating gun. To confine the cement within a close range around the wellbore, the dehydration process must occur quickly. Cement systems with high fluid-loss rates (300 to 800 mL/30 min) are used to allow a fast cake build up. It is also useful to include lost-circulation prevention agents in the slurry (powdered coal, nut-shells, sand, etc.) to act as bridging agents across the cracks and voids.

Grant and White (1987) reported success with a two-slurry squeeze design for vugular zones. A lead slurry with a short pumping time and a fairly high fluid-loss rate (300 to 500 mL/30 min) is followed by a tail slurry with a longer pumping time and a lower fluid-loss rate. The tail slurry is used for hesitation.

In high-pressure squeezing, when overcoming the formation fracture pressure, the slurry is pumped into the induced fractures, and dehydrates against the fracture walls. If the formation permeability is sufficiently high, a medium- to high-fluid-loss slurry (200 to 500 mL/30 min) will usually permit the caking and subsequent diversion of slurry to smaller cracks.

13–5.2 Slurry Volume

The appropriate volume of cement slurry depends upon the length of the interval to be cemented, and the placement technique to be used. A low-pressure squeeze requires only enough slurry to build a cement filter cake in each perforation tunnel. In many cases, less than a barrel is sufficient. However, for job convenience a 5- to 15-bbl batch is normally prepared. Pumping rates as low as 0.25 bbl/min are common. Excess cement can be included according to experience in the area; however, it must be kept in mind that excess cement could be detrimental to the productivity of the formation being squeezed.

A high-pressure squeeze, in which the formation is fractured, requires a higher volume of slurry. The volume required is a function of the width and depth of the fractures created. It has been reported that in some instances of running squeeze, where the cracks generated were excessive, volumes of more than 100 barrels of slurry have been injected (Rike and Rike, 1981). The volume can be minimized by fracturing at a low pump rate, and maintaining the injection pressure below the propagation pressure of the fractures. If the squeezing is performed at high pressures and pump rates, the fractures will develop accordingly, resulting in large quantities of cement being pumped in the formation.

Smith (1987) cited several useful rules of thumb.

- The volume should not exceed the capacity of the run-in string.
- Two sacks of cement should be used per foot of perforated intervals.
- The minimum volume should be 100 sacks if an injection rate of 2 bbl/min can be achieved after breakdown; otherwise, it should be 50 sacks.
- The volume should not be so great as to form a column that cannot be reversed out.

The hydrostatic and surface pressures must be controlled during the job. A high cement column during the displacement could cause the breakdown of low-pressure or depleted formations. When large quantities of cement are necessary (natural fractures), the use of low-density slurries is recommended.

13–5.3 Thickening Time

As with primary cementing, the temperature and pressure are important factors which influence the placement time of a cement slurry. The temperatures encountered in squeezing can be higher than those on primary jobs, because fluid circulation before the job is usually less. For this reason, special API testing schedules exist for squeeze cement slurry design (Appendix B), and must be followed to prevent premature setting.

In a shallow well, the slurry can be designed for a fairly short pumping time (e.g., two hours). Accelerators are commonly used. However, a hesitation squeeze job may require a pumping time as long as six hours. Therefore, one must add sufficient retarder to assure slurry placement, and reversing out of the excess.

13–5.4 Slurry Viscosity

The ability of the slurry to flow into narrow channels is proportional to its fluidity. Thick slurries, although useful when cementing large voids, will not flow into small restrictions unless they are subjected to high differential pressures, which are limited by the formation fracture pressure. Therefore, low-viscosity slurries containing dispersants are commonly used.

13–5.5 Compressive Strength

High compressive strength, although desirable for withstanding shocks from subsequent tools and preventing cracking during the reperforation, is not a primary concern. A partially dehydrated cement cake of any normal cement slurry will develop sufficient compressive strength.

13–5.6 Spacers and Washes

There are two major concerns related to the success of cement placement.

- Cleaning of perforations and surrounding voids. Solids-carrying fluids or drilling mud must be removed from the perforation channels and the formation face to allow a proper dehydration process and complete fill-up.
- Avoiding contamination of the cement slurry. Slurry properties, such as fluid loss, thickening time, and viscosity, can be modified by cement contact with completion fluids. A small quantity of contaminated slurry, having a high fluid-loss rate or high viscosity, may readily block channels and prevent optimum slurry placement.

In low-pressure squeezing, treatments related to the first point are performed as a separate stage. Usually, cement slurry contamination is avoided by pumping a compatible water spacer ahead of and behind the cement. If the cement is not spotted, a chemical wash or weak acid solution may be squeezed ahead of the slurry, separated by a compatible fluid.

13–6 BASIC SQUEEZE-JOB PROCEDURES

Below is a list of the general sequence of events during a squeeze job.

1. The lower zones are isolated with a retrievable or drillable bridge plug.
2. The perforations are washed with a perforation washing tool, or are reopened with the back-surging technique (Section 13–9.2).
3. The perforation washing tool is retrieved and, if the packer method is chosen, is run in the hole with the work string, set at the desired depth and tested. An annular test pressure of 1,000 psi (6.9 MPa) is usually sufficient. If the cement is to be spotted in front of the perforations, a tail pipe, covering the length of the zone plus 10 or 15 ft (3 or 5 m), is run below the packer.
4. An injection test is performed using clean, solids-free water or brine. If a low-fluid-loss completion fluid is in the hole, it must be displaced from the perforations before starting the injection test. This test gives an idea of the permeability of the formation to the filtrate.
5. The spearhead fluid followed by the cement slurry is circulated downhole with the packer bypass open. This circulation is performed to avoid squeezing the damaging fluids ahead of the slurry into the formation. A small amount of backpressure is applied on the annulus to prevent slurry free-fall as a result of the "U" tube effect.

   If no tail pipe has been run, the packer bypass must be closed two to three barrels before the slurry reaches the packer. If the cement is to be spotted in front of the perforations, with the packer unset, circulation is stopped as soon as the cement covers the selected zone. The tail pipe is pulled out of the cement slurry, and the packer is set at the desired depth.

   The depth at which the packer is set must be carefully chosen. If a tail pipe is run, the minimum distance between the perforations and the packer is limited to the length of the tail pipe. The packer must not be set too close to the perforations, as pressure communication through the annulus above the packer may cause casing collapse. A safe setting depth must be decided upon after evaluation of the quality of the cement bond with the logs (Fig. 13–12).

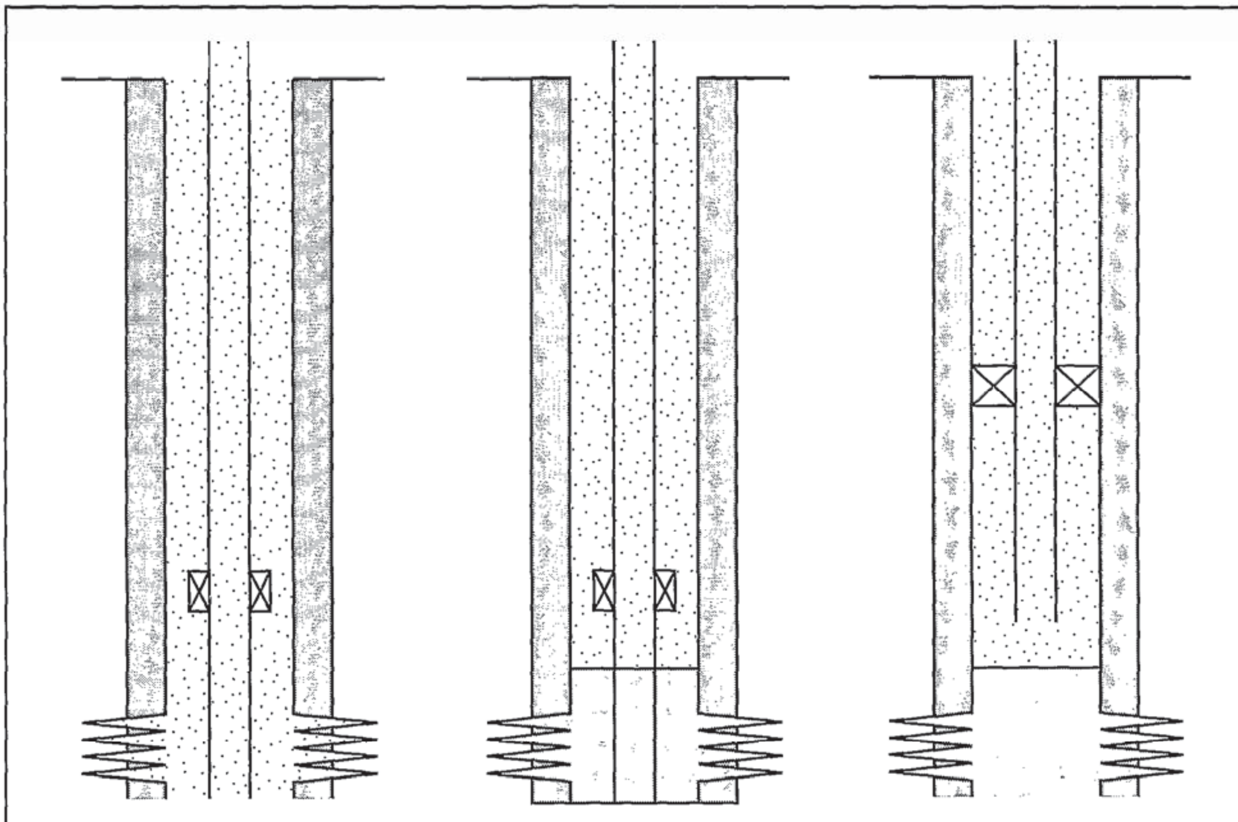


Figure 13–12—Squeeze with a retrievable packer and tail pipe.

Possible contamination of the squeeze cement by the fluid in the hole limits the maximum spacing between the packer and the treated zone. In Fig. 13–13, the packer is set too high, allowing cement slurry to be contaminated as it channels through the mud to reach the perforations. Shryock and Slagle (1968) recommended that the retrievable packer be set at no more than 25 ft (8 m) above the perforations.

6. Squeeze pressure is applied. If the hesitation method is used with the high-pressure squeeze technique, the formation is broken down, and the cement slurry is pumped into the fracture before hesitation pumping is applied. If the low-pressure squeeze technique is elected, the hesitation pumping is started as soon as the packer is set.
7. Pumping continues until no pressure leakoff is observed. A further pressure test of about 500 psi (3.5 MPa) over the final injection pressure indicates the end of the injection process. Usually, a well-cemented perforation accepts a pressure above the formation fracturing pressure, but the risk of fracturing exists if one attempts to verify such a condition.

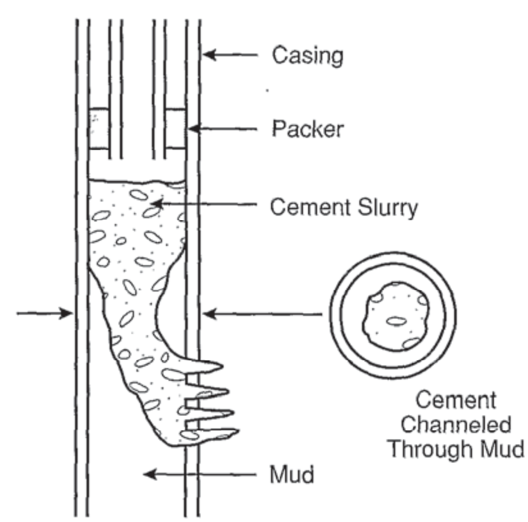


Figure 13–13—Cement slurry contamination (after Shryock and Slagle, 1968).

8. Pressure is bled off and returns are checked. The packer bypass is opened and excess cement is reversed out. Washing off cement in front of the perforations can be performed by releasing the packer, and slowly lowering the work string during the reversing; however, there is a danger of disturbing the unset cement filter cake.
9. Tools are retrieved, and the well is left undisturbed to allow the slurry to cure for the recommended waiting-on-cement (WOC) time.

When preparing the slurry, the use of a recirculating mixer or a batch tank is strongly recommended, because it ensures that the properties of the slurry pumped in the well are as close as possible to those of the slurry designed in the laboratory. On most squeeze jobs, the amount of slurry involved is quite small, but the requirements for its quality are high; therefore, special care must be taken in preparing it.

13–7 SQUEEZE CEMENTING—APPLICATIONS

13–7.1 Repairing a Deficient Primary Casing Job

Poor mud displacement during primary cementing causes the cement slurry to channel through the drilling mud. Consequently, pockets or channels of mud are left behind the casing (Fig. 13–14), and sufficient hydraulic isolation between the various permeable zones, which is the aim of the primary cementing job, is not achieved. Should such defects in zonal isolation not be corrected, serious problems may occur during the life of the well, such as those listed below.

- Stimulation treatments not meeting expected results because of poor control of the fluids placement.

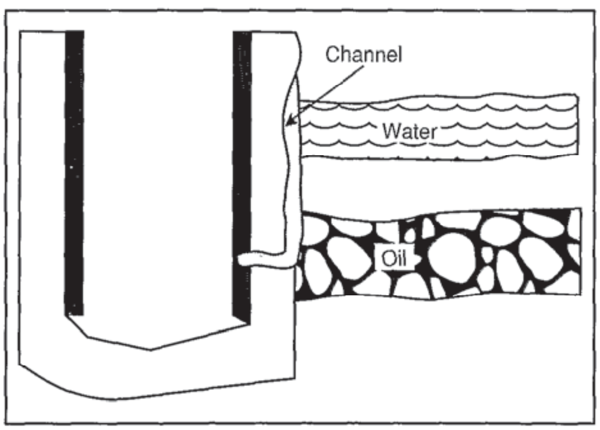


Figure 13–14—A defective primary cementing job.

- Inaccurate evaluation of the production potential of the well because of the parasitic effects of nearby flowing fluids.
- Poor well productivity as a result of water cut or high GOR.
- Failure of waterflooding project (Goolsby, 1969).

Electing to perforate a cemented casing to perform a squeeze is not an easy decision to make. Likewise, defining precisely where to perforate is also critical. A thorough analysis of the primary cementing job, based on an accurate record of all the parameters of the operation, and a careful interpretation of the logs (Chapter 16) are the key elements in aiding the decision process.

Two situations may exist behind the casing.

- The mud channel to be repaired is against a permeable formation. During the squeeze job, the cement filter cake builds and eventually fills the void.
- Circulation is established between two sets of perforations. A "circulation" or "channel" squeeze is performed to replace the mud in the channel by cement. Basically, this is a partial or total recementing of the interval of interest.

Both of these operations can be successful only if the downhole treating pressure remains below the formation fracturing pressure. Fractures created during the execution of the job would result in the opening of a preferential route through which a large quantity of the cement slurry will penetrate; as a result, damage to the permeable interval occurs, and the treatment objectives are not met.

The "circulation" squeeze, illustrated in Fig. 13–15, is often performed with a cement retainer in preference to a packer. Circulation is achieved with water or acid as a spearhead fluid. The interval is circulated with a wash fluid to ensure a good cleanup, and the cement slurry is then pumped and displaced. No pressure buildup occurs during the job, except for an increase due to the hydrostatic pressure of the column of cement as it flows up the annulus. Once the placement is completed, the stinger or packer is released. The excess cement circulating out of the upper perforations can be reversed out if desired.

There is a strong possibility that some of the cement slurry (the volume is not known, so an excess is always taken) may enter the casing, drillpipe, tubing, or the annulus above the squeeze tool during the job. Should this cement set, there is a risk that the drillpipe (or tubing) may become stuck in the hole. Thus, running a cement retainer instead of a packer is recommended to minimize

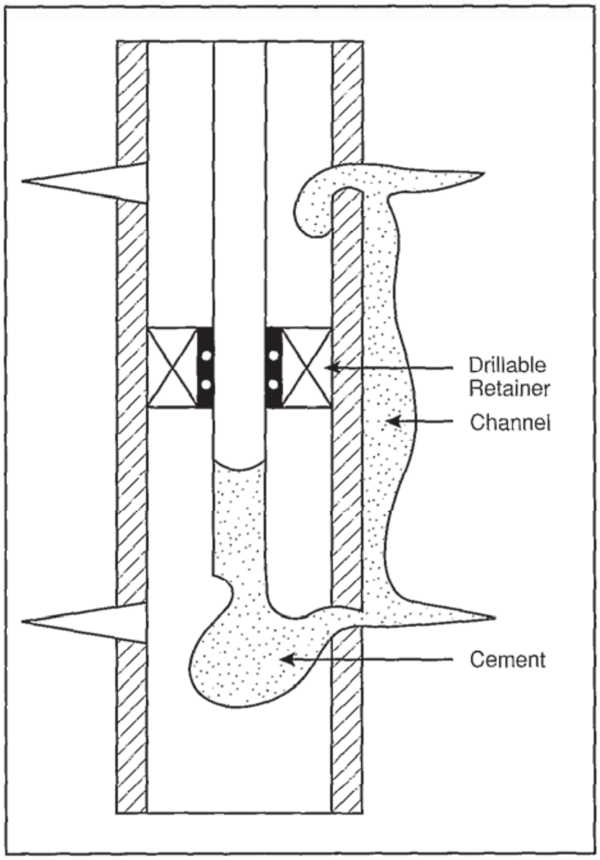


Figure 13–15—Circulating squeeze.

this risk. It is easier to remove the stinger assembly than the packer due to minimal casing clearance of the latter. Preferably, the retainer should be set as close as possible to the upper perforations to minimize the exposure of the drillpipe to cement which may enter the wellbore through the upper perforations.

13–7.2 Shutting Off Unwanted Water

Water intrusion (usually as a result of coning) may occur during the life of a well, resulting in an excessive water/oil ratio (WOR), and reduced well productivity. Remedial cementing is performed to seal off the unwanted water.

The coning water may be either bottomwater, or water which is migrating through annular channels. Such water production can only be stopped or altered if the water flows through natural or created fractures, or through channels in the primary cement sheath. Water flowing through the vertical permeability of the matrix is very difficult to stop because, during a squeeze treatment, only the cement filtrate penetrates the formation pores. The cement grains remain at the formation face.

Recently, nonparticle-laden and low-viscosity fluids, capable of forming strong gels under a wide range of downhole conditions, have been developed (Vidick et al., 1988). These fluids are able to penetrate deeper into the rock permeability, offering promising perspectives for solving water invasion problems.

Also, the use of coiled tubing units for such jobs has gained considerable popularity. Coiled tubing has proved to be a very economical method to accurately place the small volumes of cement slurry usually involved in these operations. Harrison and Blount (1986) reported that, in some instances, up to 85% savings on workover costs have been achieved when using these units. As illustrated in Fig. 13–16, the procedure can be divided into four stages.

- A supporting column of mud ("viscous pill") is injected until its level is just below the perforations to be squeezed. Some mud contamination may occur during placement, because of mixing with wellbore fluids; thus, the coiled tubing string nozzle is pulled up, and contaminated mud is circulate out. The wellbore above the mud is then loaded with water and oil or diesel.
- Cement is pumped with the nozzle located just above the mud/water interface. When the perforations are covered with cement slurry, squeeze pressure is applied. The nozzle must be kept below the water/cement interface.
- After the squeeze pressure has been attained, a contaminant fluid is injected to dilute the cement slurry.
- The contaminated cement and mud are reversed out, and the wellbore is flushed clean.

13–7.3 Reducing the GOR

During the life of a well the GOR may increase beyond the economic limit, necessitating remedial action. Such a situation is illustrated in Fig. 13–17. A common procedure is to squeeze off all the perforations in the oil and gas zones, and reperforate a selected interval (Goodwin, 1984).

13–7.4 Repairing a Casing Split or Leak

Squeeze cementing is also applied to repairing defects in the casings. However, when dealing with old and corroded casing, one should be aware that it will probably suffer more damage from the application of the treating pressure and packer-generated stresses. It may be advisable to pull out the old casing (if possible) and run a new string. Squeeze treatments performed on old wells with corroded casings often fail after a short period of time, because of the opening of new holes due to corrosion.

Casing leaks have also been spotted on new pipes, in which case a "patching" job can be designed. The

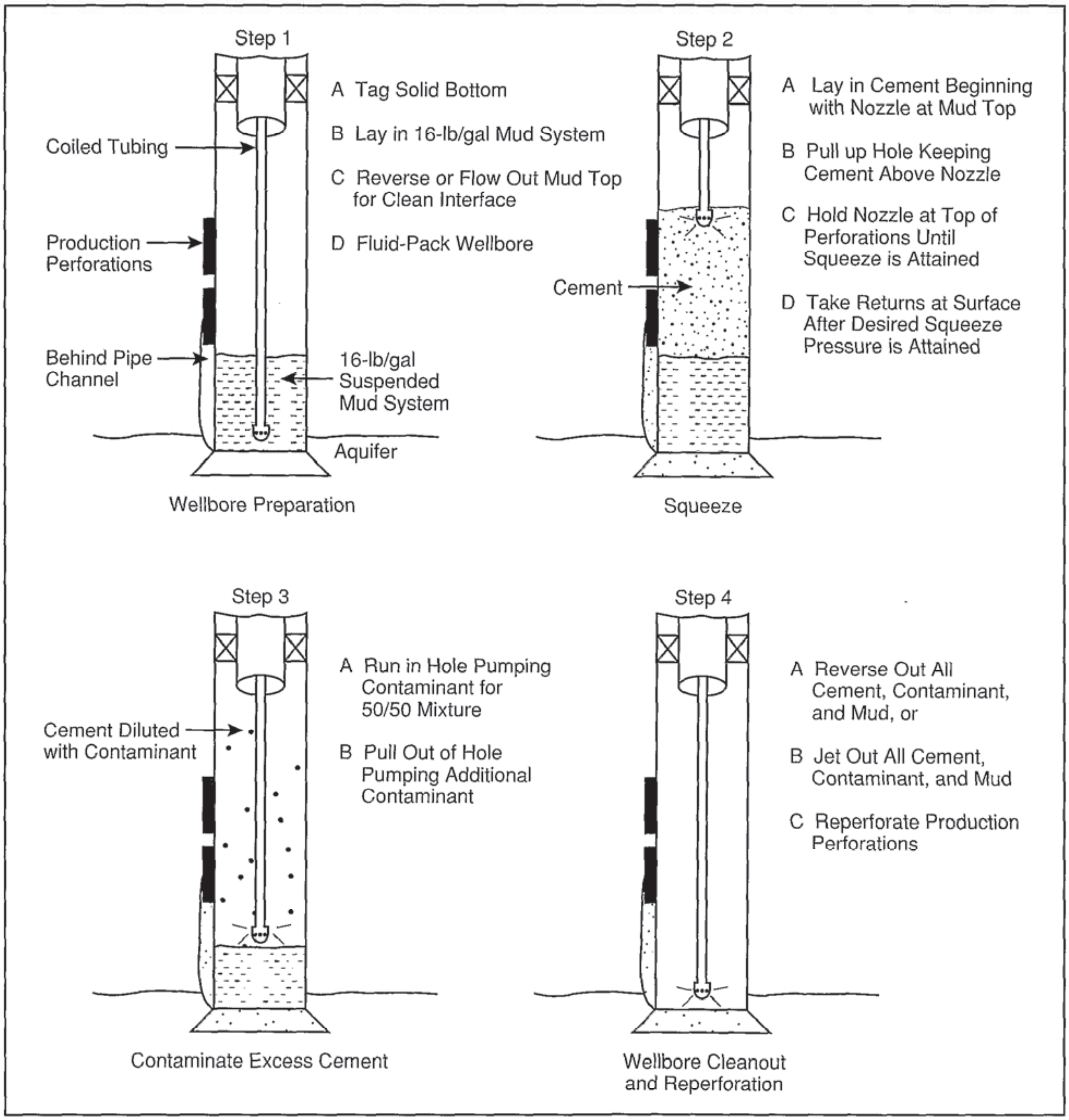


Figure 13–16—Coiled tubing squeeze (after Harrison and Blount, 1986).

squeeze is performed in the same way as one would set a cement plug, i.e, with an open-ended drillpipe (or tubing). The drillpipe or tubing is then pulled up above the cement, and squeeze pressure is applied while ensuring that the formation fracturing pressure is not reached.

13–7.5 Abandoning Nonproductive or Depleted Zones

Plugging off depleted zones is a commonly performed workover operation. The injection of the slurry is usually performed through a squeeze tool (packer or retainer),

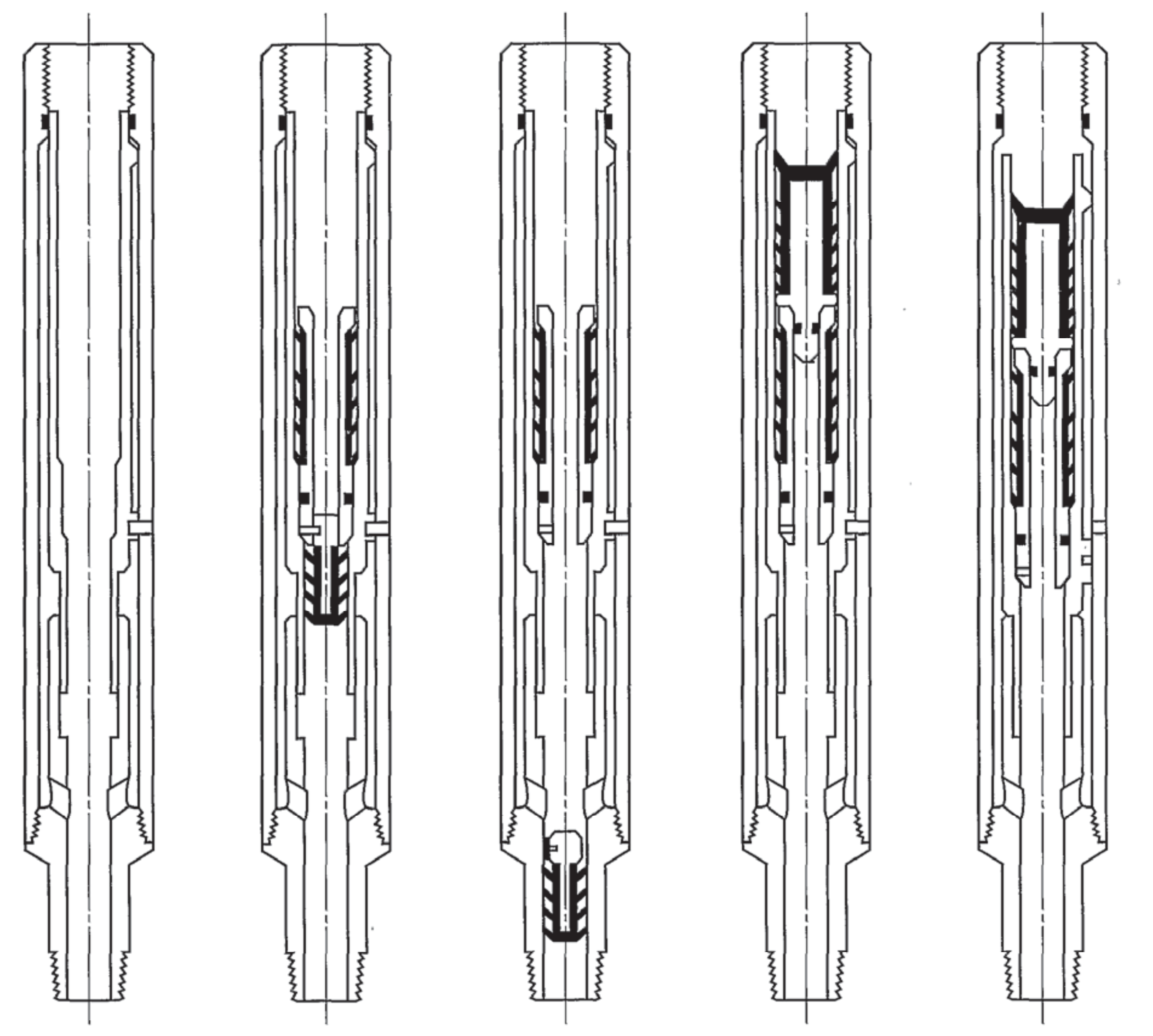


Figure 13–29—Two-plug method.

plugs. Addition of sand or weighting materials will not improve the compressive strength of a lower water content slurry. On the other hand, lost circulation or plugback jobs may require viscous low-density slurries to avoid losing the plug in the formation.

- *What is the appropriate thickening time?*

  Smith et al. (1983) recommended that the slurry pumping time be equal to the anticipated job time plus 30 minutes.

- *How does one ensure that the cement will not be contaminated with the mud?*

  The use of spacers and washes is a must, as most muds are incompatible with cement slurries. Bradford (1982) recommended that the spacer be 1 to 2 lb/gal heavier than the mud, to gain the effect of buoyancy for improved mud displacement. Smith et al. (1983) recommended that, whenever possible, spacers and washes be pumped in turbulent flow conditions. An annular height of 500 to 800 ft (152 to 244 m) is recommended. If turbulent flow is not feasible, plug flow spacers are perfectly acceptable. In addition, the use of densified cement slurries can help reduce the likelihood of mud contamination, as well as reduce the impact of the mud contamination should it occur.

- *Are pipe centralization and pipe rotation necessary?*

13–8.1 Positive Pressure Test

After the WOC time has elapsed, it is common practice to test the plugged perforations. However, this must not be considered as a test of the ability of the cement to hold the formation fluid in place; rather, the test serves as a method to diagnose a gross failure of the squeeze treatment.

The pressure applied at the face of the perforations is predetermined at the job-design stage. It may be the reservoir pressure, but should not exceed the formation fracturing pressure (Crenshaw, 1985).

Mud filter cake has been known to withstand over 5,000 psi (34.5 MPa) of differential pressure when applied from the wellbore toward the formation. Yet the same filter cake cannot withstand a significant differential pressure when applied from the formation toward the wellbore (Rike and Rike, 1981).

13–8.2 Negative Pressure Test

The universally recognized technique for confirming whether the cement in place will hold the formation fluids under producing conditions consists of applying a negative differential pressure on the face of the plugged perforations. This is accomplished by the following steps:

- circulating a light fluid (i.e., through a concentric pipe),
- swabbing the well, and
- running a dry test (Fig. 13–18) (Chapter 16).

If the sealing achieved in the perforations is complete, no inflow should be recorded on the test pressure chart (Fig. 13–19).

13–8.3 Acoustic Log

When the objective of the squeeze is to repair a primary cementing job, the normal cement logs should be run to evaluate the effectiveness of the repair by comparing pre-squeeze and post-squeeze logs (Chapter 16).

13–8.4 Temperature Profile

Goolsby (1969) evaluated squeeze results on water injector wells by comparing pre- and post-squeeze temperature profiles. By logging the well temperature after a

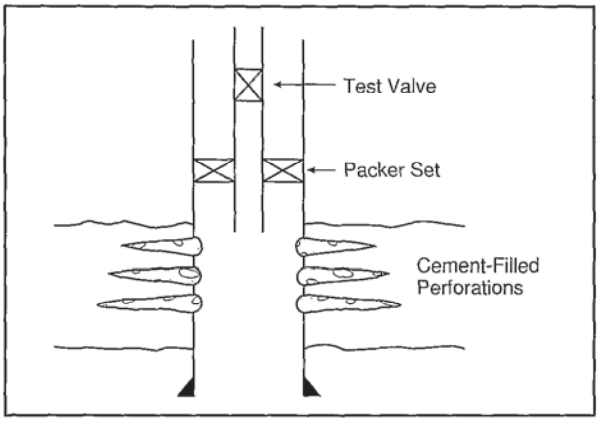
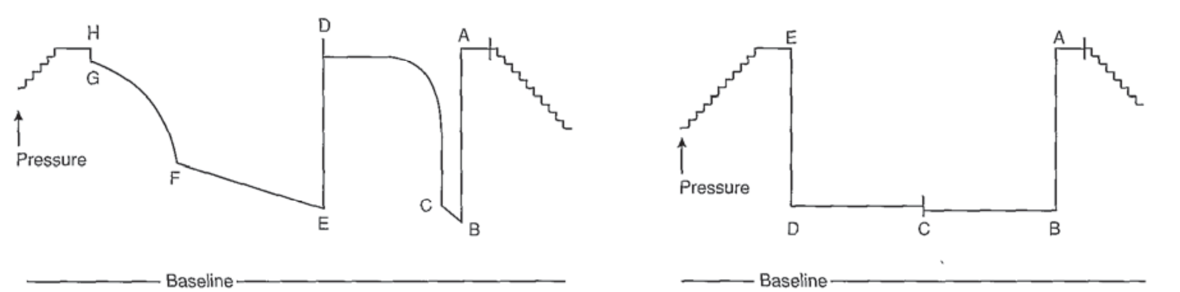


Figure 13–18—Running a dry test.



(a)

Typical DST chart of a perforated interval before cement squeezing.

A Initial hydrostatic pressure, packer set
B Initial flowing pressure (water cushion used) when test valve tool opened
B-C Flow period
C Test valve closed
C-D Pressure build up curve
D Initial shut-in pressure
E Flowing pressure after second opening of test valve tool
E-F Flow period
F Test valve closed
G Second (final) shut-in pressure
H Final hydrostatic pressure after unsetting packer

(b)

DST chart of the same interval after a successful squeeze job.

A Initial hydrostatic pressure, packer set
B "Flowing" pressure when test valve tool opened
C Pressure at the end of "flow period," test valve tool closed
D Pressure at the end of shut-in period
E Final hydrostatic pressure after unsetting packer

Figure 13–19—Dry test.

post-squeeze large injection test, he was able to demonstrate that the well was taking the injection water at the planned location.

13–8.5 Cement Hardness

Suman and Ellis (1977) reported that in squeeze jobs where cement was drilled out, a good indication of success was the nature of the cuttings. If the cement was hard throughout, the results were usually good. Soft spots or voids usually indicated a failure.

13–8.6 Radioactive Tracers

Radioactive materials may be added to the cement slurry, and subsequent tracer surveys can indicate whether the cement is in the desired interval. I^{131}, Ir^{192}, and Sc^{46} are appropriate because of their short half-lives—8 days, 75 days, and 85 days, respectively. The iridium and scandium radioisotopes are preferable, because iodine (present as iodide) is soluble, and may be squeezed out of the cement with the filtrate.

13–9 REASONS FOR SQUEEZE-CEMENTING FAILURES

Whenever a squeeze job has failed to meet the objectives, a thorough investigation must be conducted to analyze the job, understand why a failure occurred, and improve the design of subsequent treatments.

13–9.1 Misconceptions

- The cement slurry penetrates the pores of the rock.

  Only the mix-water and dissolved substances penetrate the pores, while the solids accumulate at the formation face and form the filter cake. It would require a permeability higher than 100 darcies for the cement grains to penetrate a sandstone matrix. The only way for a slurry to penetrate a formation is through fractures and large holes (vugs).

- High pressure is needed to obtain a good squeeze.

  If the formation fracturing pressure is exceeded, control of the placement of the slurry is lost, and the slurry enters unwanted areas. Pressure is of no help to place the slurry in all the desired locations. Once created, a fracture may extend across various zones, and open unwanted channels of communications between previously isolated zones.

13–9.2 Plugged Perforations

Another common misconception concerning squeeze cementing, which can lead to failure, is that all perforation holes are open and receptive to fluids (Rike and Rike, 1981). The mud filter cake, which is capable of withstanding a large differential pressure when applied from the wellbore toward the formation, easily cleans up when submitted to a differential pressure in the other direction. In addition to mud cake, debris, scale, paraffin, formation sand, pipe dope, rust, paint, etc., can accumulate in the perforations, and contribute to the plugging. Goodwin (1984) reported that, in a producing well, the upper perforations are usually open, while the plugged perforations are generally found in the lower zones. Squeezing under these well conditions results in the failure to fill all the perforations with cement, and the plugged perforations will allow the flow of formation fluids and indicate the failure of the squeeze.

Perforation washing before the squeeze job is a useful method for making all perforations receptive to the squeeze cement slurry. This can be done by mechanical or chemical means.

Mechanical perforation washing involves the use of a washing tool and back-surge techniques. The perforation washing tool (Fig. 13–20) isolates a small number of perforations at a time. A wash fluid is pumped down the tubing, forced into the perforations, then outside the casing and back through upper perforations into the annulus. The tool is slowly moved upward to cover the entire perforated interval. Common wash fluids are chemical washes containing surfactants, followed by weak acids when scales or drilling muds are to be removed. Solvents are used when paraffin deposits are present.

The surge tool (Fig. 13–21) is basically an air chamber between an upper and lower valve. The tool is run in the hole with a packer to isolate the desired interval. Once the packer is set, the lower valve is opened (annulus pressure operated), allowing fluids to enter the air chamber. The rapid depressurization of the borehole creates a high differential pressure across the perforations, and the subsequent cleanup of debris and other plugging materials from them. To establish circulation after surging, the upper valve is opened (this is accomplished by tubing movement, tubing pressure, or disk rupturing) and the debris is reverse circulated out of the hole.

The chemical perforation cleaning techniques involved the use of acids and solvents, pumped ahead of the squeeze slurry, as spearhead fluids to clean the perforations.

13–9.3 Improper Packer Location

Should the packer be set too high above the perforations, the cement slurry becomes contaminated as it channels through the mud or completion fluid. Slurry properties such as fluid loss, thickening time, and viscosity are adversely affected by contamination, and slurry placement results are altered.

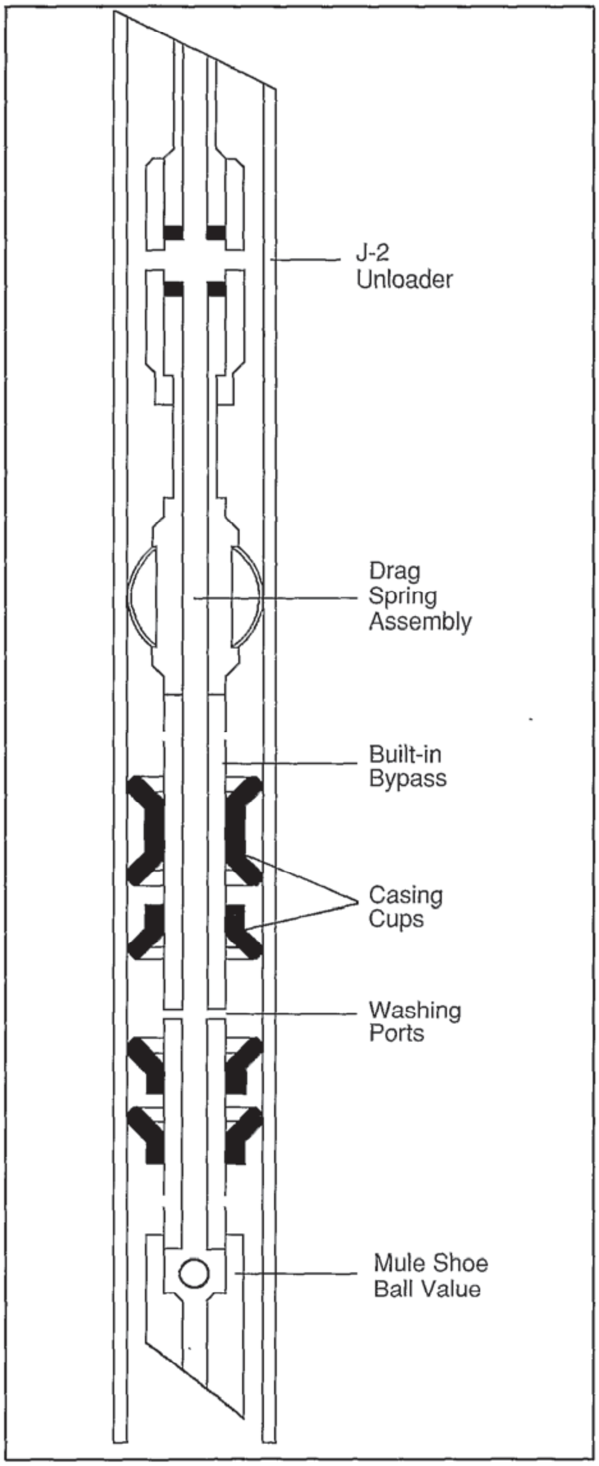


Figure 13–20—A perforation washing tool.

Shryock and Slagle (1968) recommended that the squeeze packer be set at no more than 75 ft (23 m) above the perforations. Suman and Ellis (1977) recommended that the packer be set between 30 and 60 ft (9 and 18 m) from the perforations. The use of compatible spacer

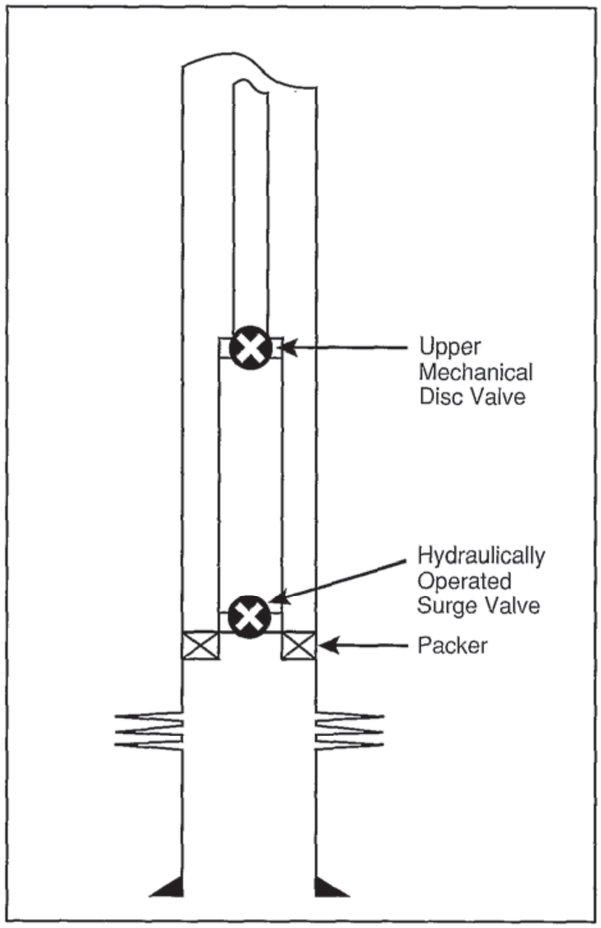


Figure 13–21—Surge tool.

fluids ahead and behind the cement slurry was also recommended.

13–9.4 High Final Squeeze Pressure

A high final pressure does not increase the chances of success; on the contrary, it increases the chances of fracturing the formation, and losing control of the cement slurry placement. It is important that a "think downhole" attitude be developed among all personnel (designer or operator) involved in this operation.

13–10 SQUEEZE CEMENTING—CONCLUSIONS

Successful squeeze cementing starts at the job-design stage. The following questions must all be answered before executing the operation.

- What is the problem?
- What are the objectives of the job?
- Which squeeze technique will be used?
- Which types of tools are to be used?
- At which depth should the packer be set?

- To which depth should the tail pipe be lowered?
- Which well preparation technique(s) is needed?
- Which type of fluid is in the hole?
- What will be the maximum job pressure?
- Which job procedure will be followed?
- What is the estimated job time?
- What are the composition and properties of the slurry?
- What quantity of slurry is necessary?
- How will the perforations be opened or cleaned?
- What is the formation breakdown pressure?
- Have other formation data (lithology, permeability, pressure, water/oil and gas/oil contact, bottomhole temperature) been considered?
- What is the WOC time?
- How will the job be evaluated?

One cannot be confident of job success, unless satisfactory answers to these questions have been received.

However, there is common thinking among authors that the most successful method is the low-pressure squeeze, with a packer or retainer as the isolation tool, using a low-fluid-loss slurry and the hesitation pumping technique. The high-pressure technique should be applied with extreme caution.

13–11 CEMENT PLUGS—INTRODUCTION

Setting a cement plug in a wall is a common oil-field operation. A cement plug involves a relatively small volume of cement slurry placed in the wellbore for various purposes:

- to sidetrack above a fish or to initiate directional drilling,
- to plug back a zone or plug back a well,
- to solve a lost-circulation problem during the drilling phase, and
- to provide an anchor for openhole tests.

The necessary equations for job design are presented in Appendix C.

13–11.1 Sidetrack and Directional Drilling (Whipstock Plug)

During directional drilling operations, it may be difficult to achieve the correct angle and direction when drilling through a soft formation (Fig. 13–22). It is a common practice to set a "whipstock plug" across the zone to achieve the desired course and target. Also, in some instances where fishing cannot be performed economically, the only remaining solution is to plug the hole with cement, and sidetrack the well above the fish.

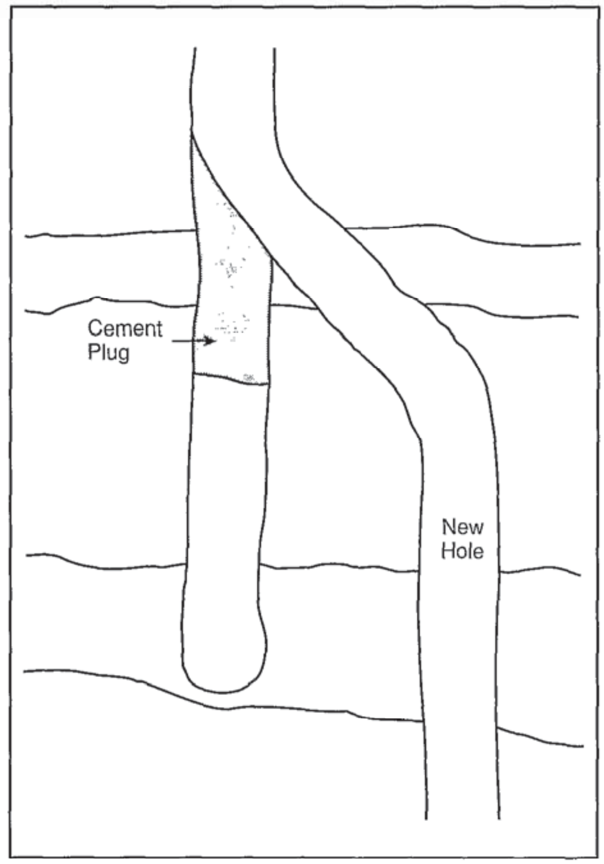


Figure 13–22—Sidetrack plug.

13–11.2 Plugback

Several cement plugs at various depths are set to abandon a well and prevent zonal communication or the migration of fluids which might pollute underground freshwater sources (Fig. 13–23). Depleted producers are also plugged with cement when they are abandoned (Fig. 13–24). In many countries, oil and gas well operators are compelled to precisely follow abandonment procedures which are dictated by government authorities.

13–11.3 Lost Circulation

Loss of drilling fluid can be stopped by setting a properly formulated cement slurry across the thief zone. Although the slurry may be lost to the thief zone, it will harden and consolidate the formation (Fig. 13–25). A cement plug can also be set on top of a zone, to protect it from being fractured under the hydrostatic pressure that might develop during the cementing of a casing string. Lost-

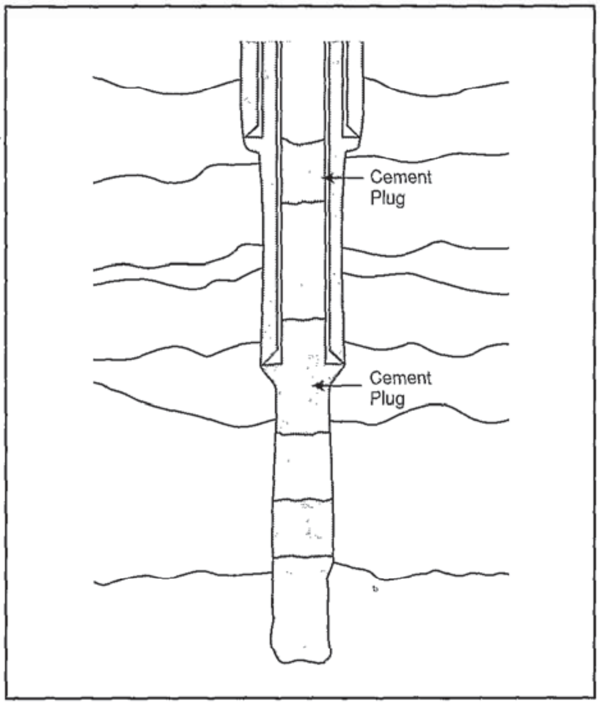


Figure 13–23—Well abandonment plugs.

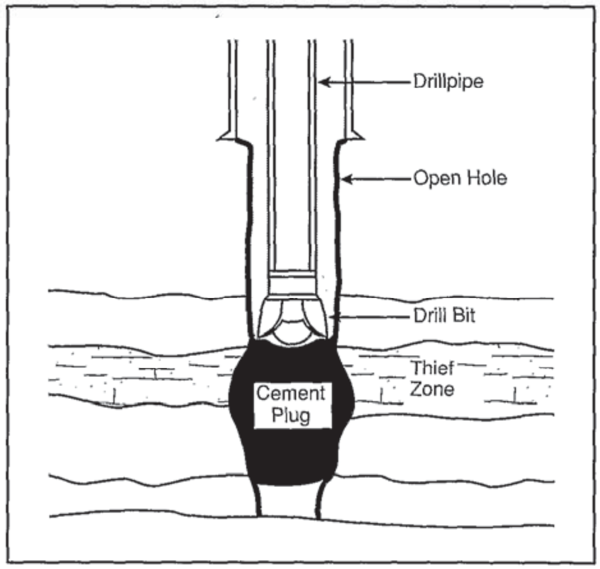


Figure 13–25—Lost circulation plug.

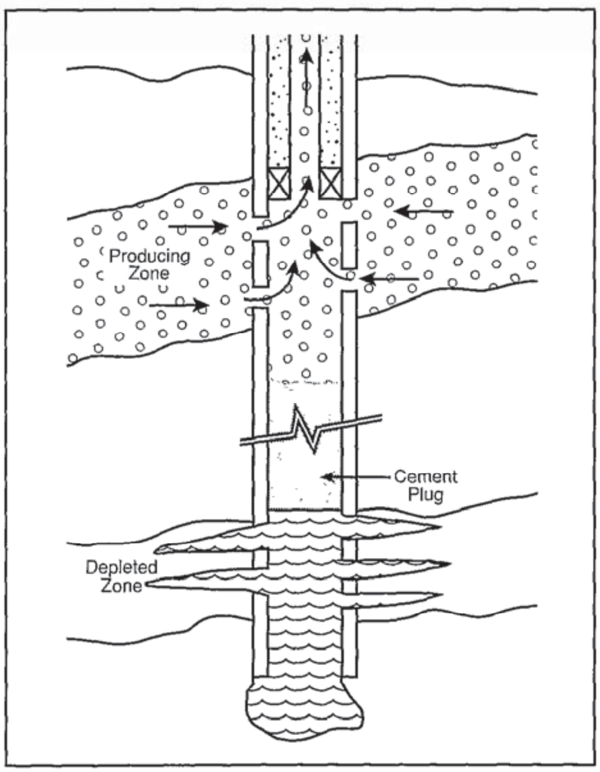


Figure 13–24—Plugging a depleted zone.

circulation additives are often added to the slurry to assure a successful job in this environment (Chapter 6).

13–11.4 Test Anchor

Cement plugs are set when a soft or weak formation exists in an open hole below the zone to be tested, and when it is impractical or impossible to set a sidewall anchor (Fig. 13–26).

13–12 PLUG PLACEMENT TECHNIQUES

There are three common techniques for placing cement plugs:

- balanced plug,
- dump bailer, and
- two-plug method.

13–12.1 Balanced Plug

The most common placement method is the balanced plug technique (Fig. 13–27). Tubing or drillpipe is run in the hole to the desired depth for the plug base. An appropriate volume of spacer or chemical wash is pumped ahead and behind the slurry to avoid any detrimental contamination of the cement by the mud. The slurry is often batch mixed for better density and rheology control.

The volumes of spacer or wash are such that their heights in the annulus and in the drillpipe or tubing are the same. Displacement is completed to the depth of the calculated plug top in the pipe. It is common practice to slightly underdisplace the plug (usually by two or three barrels) to avoid mud flowback on the rig floor when breaking the pipe after the placement, and allow the plug to reach hydrostatic balance. Once the plug is balanced, the pipe is slowly pulled out of the cement to a depth above the plug, and excess cement is reversed out.

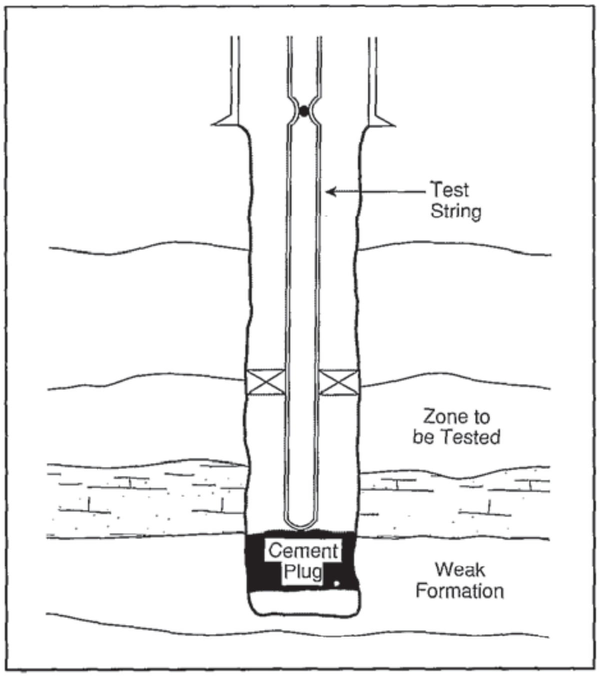


Figure 13–26—Plug set as an anchor for a test.

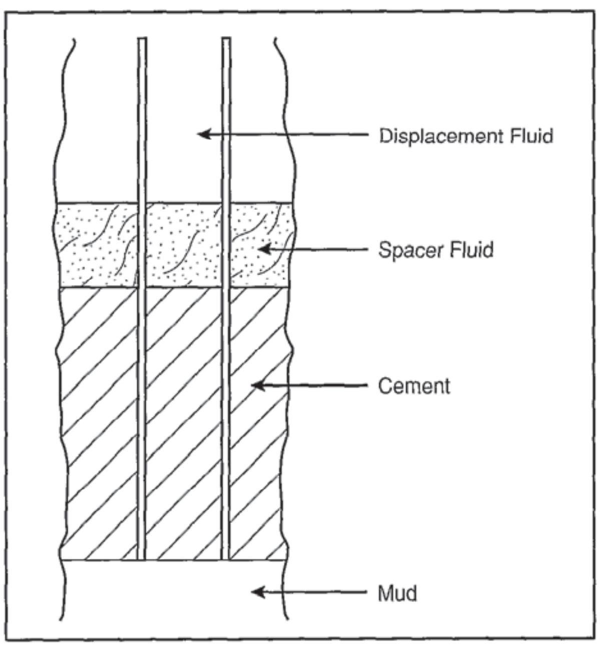


Figure 13–27—Balanced plug.

13–12.2 Dump Bailer Method

The cement is placed by running a dump bailer, containing a measured quantity of cement slurry, on a wireline. The bailer is opened by touching a permanent bridge plug placed below the desired plug interval, and the cement is dumped on the plug by raising the bailer (Fig. 13–28). Usually employed for setting plugs at shallow depths, the dump bailer method can also be used at greater depths by using properly retarded cement systems. The advantages of this method are that the depth of the cement plug is easily controlled, and it is relatively inexpensive. The principal disadvantage is that the available quantity of cement is limited to the volume of the dump bailer.

13–12.3 Two-Plug Method

This method uses a special tool to set a cement plug in a well at a calculated depth, with a maximum of accuracy and a minimum of cement contamination. The tool essentially consists of a bottomhole sub installed at the lower end of the drillpipe, an aluminum tail pipe, a bottom wiper plug (which carries a dart), and a top wiper plug (Fig. 13–29).

The bottom plug is pumped ahead of the cement slurry to clean the drillpipe wall and isolate the cement from the mud. The shear pin connecting the dart to the plug is broken by increased pump pressure, and pumped down through the aluminum tail pipe. The top plug is pumped behind the cement slurry to isolate the cement from the displacement fluid. Increased surface pressure is observed when the plug arrives at its seat. The drillpipe is pulled up until the lower end of the tail pipe reaches the calculated depth for the top of the cement plug. The shear pin between the catcher sub body and the sleeve is then broken, allowing the sleeve to slide down and unmask the reverse circulating path. If in the course of the operation the aluminum tail pipe becomes stuck in cement, an increase in the pull will break the tail pipe and free the drillpipe.

13–13 JOB-DESIGN CONSIDERATIONS

The design of the job starts with the definition of the objective. Setting a plug for lost circulation is quite different from setting a plug to abandon a depleted zone or to plug back a well. Before each job the following questions need to be answered.

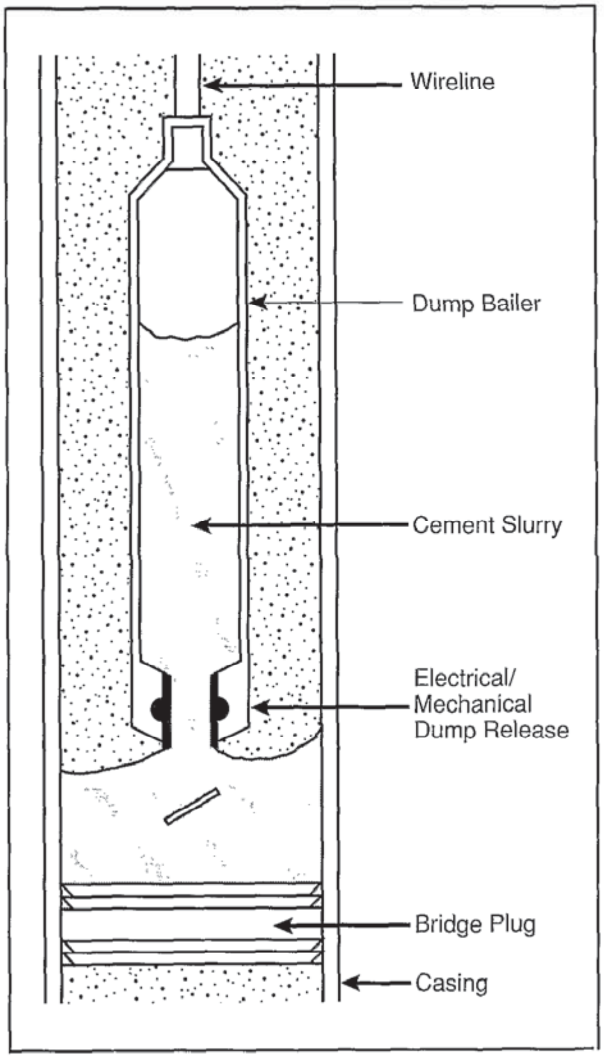


Figure 13–28—Dump bailer method.

- *At what depth will the plug be set?*

  The chances of success are greatly improved if the plug is set where the hole is near gauge. The logs should be consulted.

- *Across which formation is the plug going to be set?*

  A cement plug is best set in a competent hard rock. Shales should be avoided as they are often caved and out of gauge. However, if kicking off is the objective, the plug should not be set in an excessively hard formation. Ideally, the plug should extend from a soft shale down to a hard formation (Dees and Spradlin, 1982). In any case, the logs and the drilling rate record should be consulted when selecting a location to set a plug.

- *At what density should the slurry be mixed?*

  The higher the density differential between the slurry and the drilling fluid, the higher the chance that the slurry will migrate downward. Proven techniques that prevent this phenomenon are described below. On the other hand, a lighter slurry will result in a lower the compressive strength. On average, a 15.8-lb/gal (1.90-g/cm^3) slurry develops a final compressive strength of at least 5,000 psi (34.5 MPa). A reduced water slurry of 17.5 lb/gal (2.10 g/cm^3) develops a final compressive strength of at least 8,500 psi (58.6 MPa).

  For better control of the slurry density, the batch-mixing technique is preferable (Smith et al., 1983). Slurry densities usually range from 15.6 lb/gal (1.87 g/cm^3) to 17.5 lb/gal (2.10 g/cm^3) to ensure good compressive strength development.

- *What is the bottomhole temperature?*

  The API recommends that well simulation test procedures follow simulated Squeeze Cementing Schedules 12 through 21 (Appendix B).

- *What volume should be pumped?*

  The amount of cement depends upon the objective of the plug. The lengths and depths of abandonment plugs are usually dictated by government regulations. Whipstock plugs must be very long to provide for a gradual deviation of the bit. A caliper of the hole is very useful. The size of the cement plug should be 300 to 900 ft (91 to 274 m) of annular fill (Smith et al., 1983). Care must be taken to avoid excessive hydrostatic pressure on lower depleted or weak zones; otherwise, the plug may not be placed at the desired depth.

- *Is mud conditioning necessary prior to the operation?*

  A low-rheology mud is easier to displace.

- *What are the appropriate slurry properties?*

  Viscous slurries with high gel strength are needed for lost-circulation plugs, to restrict flow into voids or fractures. When the difference between cement density and hole fluid density is high, the cement will tend to fall through the lighter fluid. In this case, thixotropic slurries may solve the problem. Another approach is to place a viscous bentonite mud pill below the intended plug depth to act as a support medium for the cement (Fig. 13–30) (Smith et al., 1983). As shown in Fig. 13–31, a diverter tool is recommended. Such tools minimize the risk of the heavy slurry "telescoping" through the mud, but diverting the fluid flow through side ports at the bottom of the work string.

  High compressive strength is mandatory in whipstocking to have a sharp contrast between the plug and formation hardness. Since compressive strength is a function of the water/solids ratio, high-density (low water/solids ratio) slurries are best suited for such

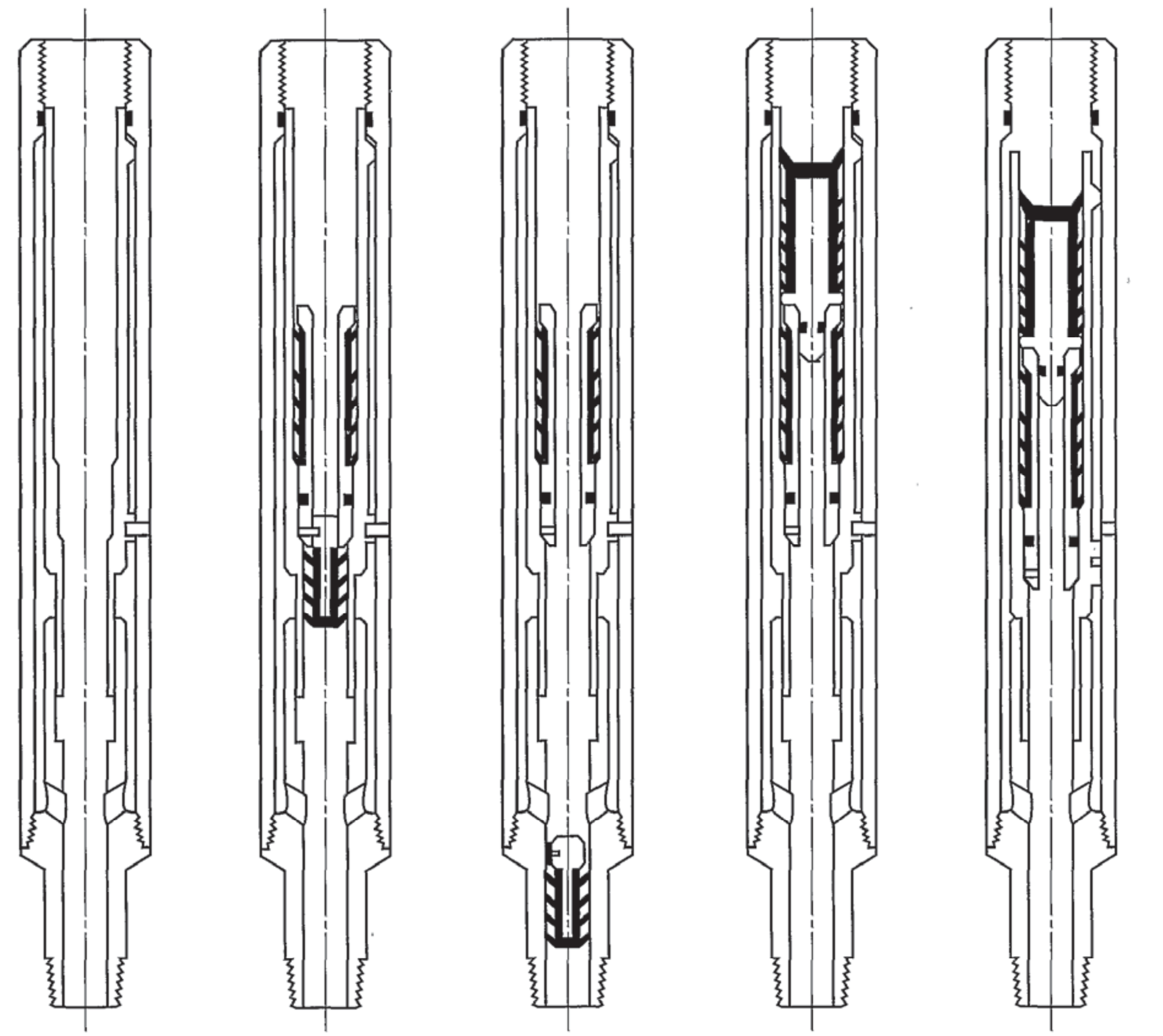


Figure 13–29—Two-plug method.

plugs. Addition of sand or weighting materials will not improve the compressive strength of a lower water content slurry. On the other hand, lost circulation or plugback jobs may require viscous low-density slurries to avoid losing the plug in the formation.

- *What is the appropriate thickening time?*

  Smith et al. (1983) recommended that the slurry pumping time be equal to the anticipated job time plus 30 minutes.

- *How does one ensure that the cement will not be contaminated with the mud?*

  The use of spacers and washes is a must, as most muds are incompatible with cement slurries. Bradford (1982) recommended that the spacer be 1 to 2 lb/gal heavier than the mud, to gain the effect of buoyancy for improved mud displacement. Smith et al. (1983) recommended that, whenever possible, spacers and washes be pumped in turbulent flow conditions. An annular height of 500 to 800 ft (152 to 244 m) is recommended. If turbulent flow is not feasible, plug flow spacers are perfectly acceptable. In addition, the use of densified cement slurries can help reduce the likelihood of mud contamination, as well as reduce the impact of the mud contamination should it occur.

- *Are pipe centralization and pipe rotation necessary?*

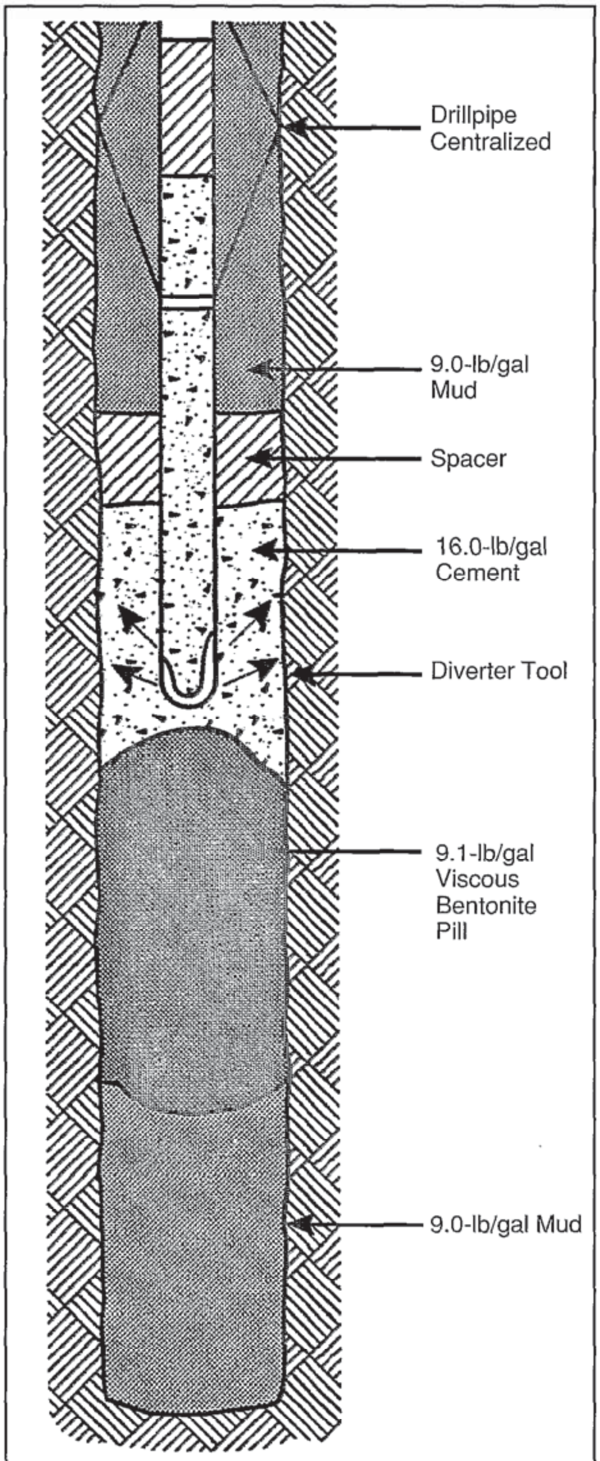


Figure 13–30—Recommended technique for placement of bentonite pill (after Smith et al., 1983).

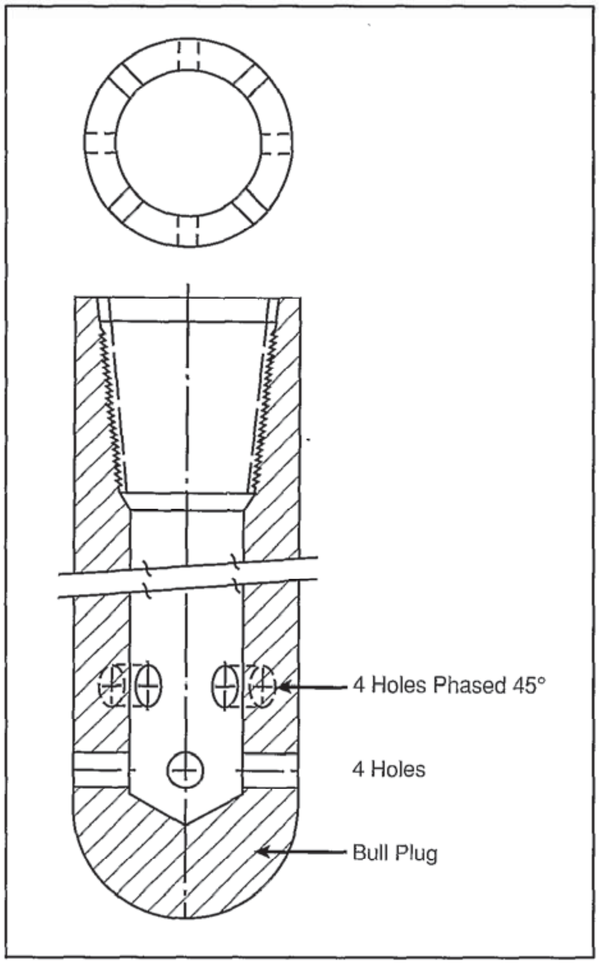


Figure 3–31—Flow diverter tool (after Smith et al., 1983).

Bradford (1982) recommended that the pipe be carefully centralized. This precaution can dramatically improve mud removal. Pipe rotation is also cited as an advisable practice.

- *Waiting on cement time?*

  Early compressive strength depends heavily on the thickening time. Rig time can be saved with a proper slurry design. The slurries must be designed for a thickening time in accordance with well conditions and job procedures, plus a reasonable safety factor. Smith et al. (1983) recommended that ample WOC time be allocated (12 to 24 hours). Since the well temperature for a cement plug job is difficult to know accurately, a common practice is to allow for longer WOC times. A minimum of 500-psi (3.5-MPa) compressive strength is normally recommended for drilling out cement.

13–14 EVALUATION OF THE JOB, REASONS FOR FAILURES

After the WOC time has elapsed, the job results are evaluated. This is normally done by tagging the cement. Depth of the top of the plug and hardness of the cement are the key indicators to measure success or failure. Whenever a cement plug has failed to meet the objectives of the job, the reason(s) for the failure should be carefully investigated to modify and improve the design of the repeated attempt and to be successful the next time. Some of the most common causes of failure are listed below.

- *Mud Contamination*

  Mud contamination is recognized as a major cause of cement plug failure (Bradford, 1982; Smith et al., 1983). Mud contamination dramatically affects the cement compressive strength (Table 13–4). This contamination may result from a poorly centralized pipe. If the tubing or drillpipe is not properly centralized, it will stand on one side and the slurry coming out of the bottom will follow the path of least resistance—the open side. Cement channels in the mud, and mixes with the mud when the pipe is pulled out of the hole.

- *Insufficient Cement Volume*

  The plug may have been set in a washout or a poorly calibrated section of hole; therefore, its height is not adequate. Also, in large hole sections, mud displacement is difficult, immobile gelled mud is present, and chances of contaminating the slurry are high. It is strongly recommended to place the plug in a well-calibrated hole section.

  Bradford (1982) and Dees and Spradlin (1982) recommended a minimum of 500 ft (152 m) for plug height. Smith et al. (1983) recommended that the plug size should be 300 to 900 ft (91 to 274 m). The extra cement required is very economical when compared to the costs associated with repeating the job, waiting again on cement, retesting the plug, etc.

- *Plug Slipped Downhole*

  Smith et al. (1983) recognized that a heavy cement resting on top of a lightweight mud forms an unstable interface; as a result, the cement channels downward and becomes diluted in the mud (Fig 13–32).. The common practice of using an open-ended drillpipe is a major contributor to plug failure, as the cement turning the shoe causes considerable disturbances to the interface. As discussed earlier, this problem can be remedied by the placement of a viscous mud pill with a diverter tool. As an alternative, a delayed-gel fluid could be used instead of the bentonite pill.

  Bour et al. (1986) recommended the placement of a reactive fluids system (RFS), which creates a rapid forming gel acting as a bridge upon which the cement slurry can rest. As a slurry, they recommended the use of an adequate gel strength cement (thixotropic) to counteract the density differential driving forces.

13–15 PLUG CEMENTING—CONCLUSIONS

The implementation of the simple techniques and guidelines described above have resulted in a significant success rate improvement. There are no requirements for large investment, and yet significant savings can be achieved. The following is a list of measures that should be taken (Smith et al., 1983).

- Place the plug in a competent formation (i.e., a hard formation).
- Use ample cement.
- Use a tail pipe through plugback intervals.
- Use scratchers or wipers and centralizers on the tail pipe where the hole is not excessively washed out.
- Use a drillpipe plug and a plug catcher.

Neat Class H Cement 16.5 lb/gal			Effect of Mud Contamination*		
Mud Contamination (% by volume)	Compressive Strength (psi at 170°F) 8 hr	16 hr	Mud Contamination (%)	Normal Slurry 15.6 lb/gal	Reduced Water Slurry** 17.5 lb/gal
0	4,647	5,862	0	4,082 psi	8,600 psi
5	3,512	5,300	10	2,950 psi	8,237 psi
10	2,619	4,538	40	2,426 psi	3,850 psi
20	2,378	2,331	60	593 psi	2,967 psi
50	245	471			

* Compressive strength in 18 hr at 230°F.
** Contains dispersant.

Table 13–4—Effect of mud contamination on set cement compressive strength.

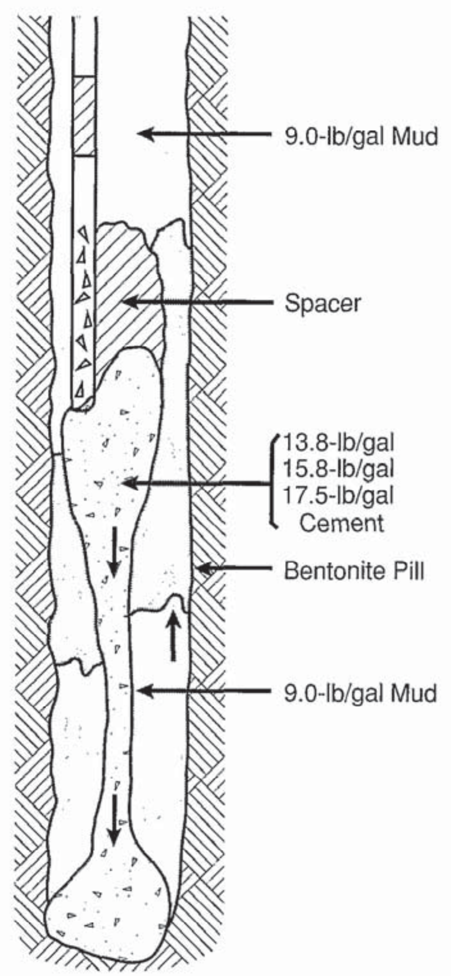


Figure 13–32—The unstable interface (after Smith et al., 1983).

- Circulate the hole sufficiently before running the job. Use a mud of low yield point and low plastic viscosity, but of sufficient weight to control the well.
- Ahead of the cement, run a flush and/or bentonite pill that is compatible with the mud and will prevent the cement from sliding down from the hole.
- Use densified cements with a dispersant to combat the effects of mud contamination. Spacers and washes are also useful.
- Allow ample time for the cement to set.

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