Results of Calculations

The following table presents the results of the nine calculations for Squeeze Problem Two:

Squeeze Cementing Calculation Results	
Description	Result
① Volume of cement (bbl).	28.32 bbl
② Pressure to reverse one barrel of slurry from workstring.	72.37 psi/bbl
③ Minimum water requirements.	89.18 bbl
④ Displacement volume to spot cement one barrel above packer.	6.58 bbl
⑤ Pressure to reverse cement when spotted.	2,050 psi
⑥ Pressure to reverse cement from workstring when cement reaches top perforation.	1,932 psi
⑦ Pressure to reverse cement from workstring when cement reaches bottom perforation.	1,903 psi
⑧ Maximum pump pressure when cement slurry has reached the bottom perforation	347 psi
⑨ Pressure to reverse out at the completion of the job	789 psi
⑩ Amount of cement pumped through the perforations	82 sk
⑪ Maximum pump pressure if the channel is full of cement	1,481 psi

Always check whether or not to apply backup-pressure on the annulus to prevent cement slurry squeeze pressures from collapsing the casing above the packer. This may be very important for older casing strings when performing high pressure squeezes where the cement fractures behind the pipe and applies pressure upward to the outside of the casing above the packer.

Unit B Quiz

Fill in the blanks with one or more words to check your progress in Unit B.

1. The well parameters needed for squeeze calculations include:

   ____

   ____

   ____

   ____

   ____

2. To convert a given volume of cement from sacks to barrels, you must determine the ______________ __________________________.

Now check your answers in the Answer Key at the back of this chapter.

Special Procedures for Difficult Well Conditions and Applications

As wells are being drilled deeper with complex configurations, such as those in horizontal wells, and with harsh hole conditions with high temperatures and pressures, special squeeze cementing procedures may be needed to improve job success rates. The rejuvenation of oil and gas production in mature fields, especially when applying secondary and tertiary recovery methods, may also have difficult conditions such as low cement fill from outdated practices or degraded cement from corrosive environments that require the installation of new well barriers or the repair of old ones by squeeze cementing. To be effective well barriers, squeeze cements must be pumped into the designed location inside and/or outside of the well which can be a challenge in difficult well conditions. Sometime cement slurries don't have the required placement and sealing properties and, instead, non-cements must be used to accomplish the desired task. The following mentions some of the difficult conditions and methods that may make squeezing more successful.

Cement Squeeze Placement vs. Fluid Loss Control

When cement slurries contact formations during squeeze operations, the slurry's fluid loss control and the permeability of the zone can either inhibit or help in placing the slurry at the desired location behind the pipe. Figure 8.22 shows that, depending on fluid loss control, the cement slurry can dehydrate and cause filter cake buildup inside the perforations and the casing. For example, when the cement slurry doesn't have fluid loss control (e.g., 1,000 cu cm/30min), the top perforation in Figure 8.22 has a rapid buildup of cake that can block the flow of slurry and prevent the proper placement of cement behind the pipe. This can happen in all the perforations when the total volume of slurry has no fluid loss control and formations are permeable. If the slurry had fluid loss control this improper placement can be avoided as illustrated in the other perforations in Figure 8.22. As the cement fluid loss is reduced in the lower perforations in Figure 8.22 down to 150 to 25 (cm^3/30min), the cake buildup is delayed long enough to allow the flow of slurry to enter the perforations and travel to the designed location in the annulus between the pipe and formation. This also helps prevent the loss of the low-pressure squeeze placement which causes unwanted higher squeeze pressures that can fracture the formations in the annulus. If formations in the annulus have very little permeability such as in shale formations, the cement cake buildup may be reduced. However, some shales and other low permeability zones may be "microfractured" which may still cause cement dehydration and cake buildup.

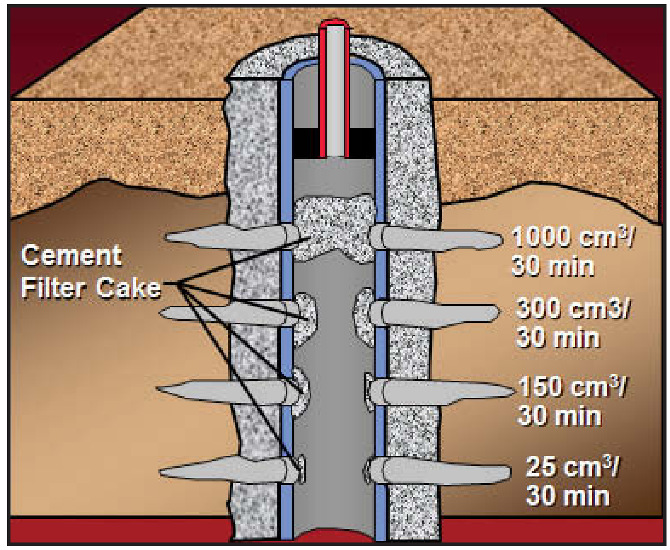

FIGURE 8.22: CEMENT FILTER CAKE BUILDUP INSIDE CASING AND PERFORATIONS.

Squeeze Slurry Designs for Challenging Jobs

Table 8.3 provides typical squeeze slurry types and properties used for some difficult applications and conditions.

Table 8.3: Common squeeze solutions for difficult applications	
Challenge	Common slurry types and properties
Casing shoe squeeze for failed shoe test	Standard density, high fluid-loss, fast dehydrating slurry or moderate fluid-loss slurry followed by high fluid-loss slurry. Special systems are available to restore shoe integrity or to increase it above the fracture gradient.
Liner top squeeze for failed pressure test	Low fluid-loss slurry to prevent bridging in tight annulus. Special systems such as micro-fine cements and polymer gels may be necessary.
Sealing water zones or lost circulation intervals	Thixotropic cement, no fluid-loss control, LCM additives. May need barrier to squeeze against (i.e. $CaCl_2$ brine and sodium silicate spearhead). Polymer gel systems may be needed for sealing water zones. Special lost circulation reactive squeeze systems may be needed for severe loss conditions.
Shutting off high rate water flows	Cement slurry oil squeeze or gunk squeeze, or larger water seal-off cement design with silicate spearhead and LCM. Special water-reactive systems are often needed for severe flows. Shallow water flows in deepwater wells requires other preventive and remedial methods as described in API RP 65 (Part 1) titled "Cementing Shallow Water Flow Zones in Deep Water Wells."
Sealing high-perm formations	Low pressure and hesitation squeezes with low fluid-loss slurries sometimes followed by high fluid-loss slurries.
Sealing vugular or fractured formations	Thixotropic cements followed by moderate fluid-loss slurry. Foam cement is often needed for large vugs and large natural fractures.
Blocking low-perm formations	Low to moderate fluid-loss slurry for greater penetration in high-pressure squeezes. Chemical sealants that can penetrate into very low permeability formations may also be needed in some cases.
Squeeze lower performations	Low fluid-loss slurry to prevent dehydration in casing and improve penetration into the lower zone. Do not use LCM.
Repair split casing	No fluid-loss control for short sections. Use thixotropic slurry for long sections.
Plug holes in corroded casing	Low fluid-loss slurries; or thixotropic cements followed by low fluid-loss slurries.
Sealing long perforated intervals	Low fluid-loss slurries; or low fluid-loss followed by high fluid-loss slurries in low pressure and hesitation squeezes.
Sealing failed pipe connections	Extremely low fluid-loss cements or special systems such as epoxy resin or very fine grind cements such as a micro-fine cement. Chemical sealants that can penetrate into very small openings may also be needed in some cases.
Wellbore strengthening and conformance while drilling	See dedicated section in this chapter, beginning on opposite page.

Squeezing for Wellbore Strengthening and Conformance While Drilling

"Wellbore Strengthening" while drilling (WSWD) and "Conformance While Drilling" (CWD) are the terms for types of fluid squeeze treatments that enable drilling, completion, and interval isolation by increasing wellbore pressure containment (WPC) and restoring wellbore stability or preventing instability, i.e., stopping or preventing lost circulation and formation fluid influxes, and/or providing structural integrity to various types of rock formations including sands, shales, and carbonate formations. WSWD can address potential or actual "leaking" formations that have in- and/or out-fluxing (aka, unwanted flows into or out of formations) of fluids via flow paths in natural or induced fractures, fissures, faults, and high permeability. When both in- and out-fluxing occur in the same hole, the condition is described as crossflows or, in severe cases, underground blowouts. The former condition is often not severe enough to stop drilling deeper or well completion and the latter one is typically a "show stopper" where immediate action is required to stop the flows so drilling deeper or completion operations can continue.

CWD is a similar process to WSWD that is most often used in or adjacent to the production hole section to reduce or prevent the production of unwanted fluids such as water in oil and gas pay zones and gas in oil pay zones. CWD treatments add steps to the WSWD/CWD process that will evaluate the potential formation damage by treating the pay zone and determine treatments that will either prevent impairment of the pay zone's permeability or allow removal of the impairment during completion operations.

WSWD and CWD Processes

- Identifying the hole integrity problem in as much detail as possible such as,
  - Analyzing mud logger data for targeting formations causing the problem
  - Checking offset well data for the same issue and any solutions
- Diagnosing the issue and characterizing the target formations:
  - Analysis of loss rates and other drilling or completion operations data;
  - Details on influx and/or leak-off or loss events in target formations;
  - LWD or MWD data analysis and conversion into modeling input data;
  - Lost circulation and formation modeling to calculate fracture geometry, stresses, etc.;
  - Treatment placement modeling for WCWD or CWD;
  - Analyze potential production impairment, if treating in or near pay zones
- Selecting the type of treatment system;
- Designing the treatment placement procedure;
- Evaluation of treatment results prior to drilling ahead:
  - Testing with FIT (formation integrity test) and LOT (leak-off test);
  - Or testing via mud logger data (in- vs. out-flow) to check for losses and influxes;

Treatment Types

1. LCM Mud Pills and "Fluid Loss Pills"

Lost Circulation Materials (LCM) added to pills spotted across or squeezed into loss zones, i.e., circulated down DP into the annulus across the loss zone or "bull-headed" into the loss zone with the end of the DP a safe distance above the loss zone. The LCM particles then enter into the loss zone's leak-off flow paths to form bridges at narrow points within the path that may seal them. Many different types of LCM are available depending on conditions such as the loss rate, drilling or completion fluid type, loss path size, etc. Some LCM are acid soluble to allow removal during completion of pay zones. LCM mud pills often are successful in reducing drilling and completion fluid losses and, depending on the severity of the losses, improving wellbore integrity and WPC (aka, drilling or completion pressure containment).

2. Resin and Gel Systems

Some friable and unconsolidated sands are candidates for resin and gel systems with "settable filtrates" that can add structural integrity in the formation. This may help prevent breakouts and cave-ins during drilling along with stopping seepage losses. Gel systems with "gellable filtrates" may be better for sands with adequate mechanical strength to resist drilling forces while sealing the perm. Both types of "filtrate sealant" systems can be formulated with sized solids to limit pore throat penetration of filtrate enough for perforations to reach unsealed permeability in pay zones. Papers SPE 79861 (van Oort, 2003) and SPE 53312 (Sweatman, 1999) have more information on these and other systems. Figure 8.23 shows a cross-section of a core sample that was squeeze treated in a lab test by a resin system to increase the structural strength of the permeable rock formation during drilling operations. The dark grey area of the core is the "settable filtrate" deposited from squeezing resin filtrate from the hole in the center of the core that penetrated into the rock's permeability. The core section untreated by the resin is the lighter grey area.

3. Reactive Pills

Reactive pills are fluid compositions designed to chemically react, upon contact with other fluids present in the well such as drilling, completion, cementing, and formation fluids, to form sealing materials that are squeezed inside formation permeability or voids (fractures, vugs, etc.) or both. Many different types of reactive pills have been developed for various drilling and completion applications that help enable interval isolation. Some of the most commonly used ones are described below:

- Sodium silicate spacer or squeeze systems;
- Diaseal M High Fluid Loss Squeeze systems;
- Gunk squeeze systems such as slurries of:
    - Diesel oil and bentonite (DBO);
    - Diesel oil, bentonite, and 2 parts cement (DOB2C);
    - Diesel oil and cement (DOC);

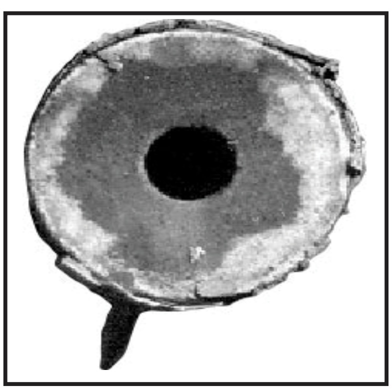

FIGURE 8.23: CORE SAMPLE SQUEEZE TREATED BY A RESIN SYSTEM.

- "Super-Gunk" squeeze systems that add other materials such as polymers;
- Latex and latex-resin squeeze systems;
- Shear activated squeeze systems;
- Heat activated squeeze systems.

4. DVC Squeeze Systems

DVC (deformable, viscous & cohesive) squeeze systems are a special class of reactive material systems with documented LOT and FIT data that quantifies successful WSWD process applications. The following generic descriptions are for two common types of DVC System slurries for WSWD applications:

A. DVC-OBM, modified versions and new replacement products:

This version is designed to react downhole with almost all non-aqueous fluid (diesel oil, mineral oil, and synthetic oil) based drilling and completion fluids to halt severe lost circulation or to increase LOT/FIT pressures. It also reacts with natural gas and CO_2. The chemical formulation is composed of various concentrations of several different components slurried in fresh water and including reactive minerals, a form of latex (BS copolymer), latex stability agents, and PH stabilizers. The following modifications may explain the next generation of WSWD sealant. Some of the listed modifications have been successfully field tested under the name "modified DVC-OBM" and generically named in publications with improved downhole performance such as higher increases in LOT/FIT pressures:

- May be "on-the-fly mixed" with bulk powder into an RCM or with a liquefied powder into the cement unit;
- New downhole in-situ mixed additives to increase rheology and cohesion and reduce fluid loss;
- Higher concentrations of surface mixed components for increased 'below the bit" rheology and cohesion and reduced fluid loss;
- May be densified to enhance placement in multiple formation intervals and prevent premature node buildup and hole pack-offs in upper leakoff flow-paths;
- Initial latex may be replaced by a better performing liquid latex and a dry powdered version.

B. DVC-W, modified versions and future replacement products:

Designed to react downhole with almost all water based drilling and completion fluids to cure severe losses and increase LOT/FIT pressures. It also reacts with formation waters. The formulation includes a blend of reactive minerals, polymers and catalysts slurried in a diesel oil, mineral oil, or synthetic oil base fluid. The following modifications may explain the next generation of WSWD sealant. Some of the listed modifications have been successfully field tested under the name "modified DVC-W" and generically named in publications with improved downhole performance such as higher increases in LOT/FIT pressures:

- May be "on-the-fly mixed" with bulk powder into an RCM or with a liquefied powder into the cement unit;
- New downhole in-situ mixed additives to increase rheology and cohesion and reduce fluid loss;
- Higher concentrations of surface mixed components for increased "below the bit" rheology and cohesion and reduced fluid loss;
- May be densified to enhance placement in multiple formation intervals and prevent premature node buildup and hole packoffs in upper leakoff flowpaths;
- Some components may be replaced by better performing ones.

Downhole Reacted Material Properties and Placement for Both Types of DVC System Slurries

During a squeeze into exposed formations in an open hole, the DVC system slurry co-mingles with the well fluid below the bit and above the leak-off flow-paths into formations. Commonly found or added ions in the commingled well fluid trigger chemical reactions to rapidly change the slurry and mud mixture from easily pumped viscosities into extremely high viscosities that finger through the well fluid before entering the formation. The fingers aggregate to form strings of semi-solid agglutinates. The agglutinates are often larger in size than the openings into formations such as fractures, faults, and small vugs. The agglutinates can't easily flow into the formation openings and must be extruded under pressure to propagate a few feet while simultaneously agglomerating into a flexible seal. The seal may hold differential pressures from several hundred to several thousand psi. The highest recorded field test positive differential pressure is 3,647 psi measured after an FIT. The highest recorded differential pressure seal between high and low pore pressure formations is 10,410 psi.

These sealants may sequentially seal multiple cracks or narrow openings in several exposed formations over long open hole intervals starting with the initial flow-path of least resistance to the next and the next by the agglutinates' self-diverting properties. Moldable and high cohesive properties cause the agglutinates to form-fit in openings and maintain a seal under designed pressure differentials, controlled swab-surge loads, and HTHP conditions. The record for sealing durability is 7 months exposed to 11,000

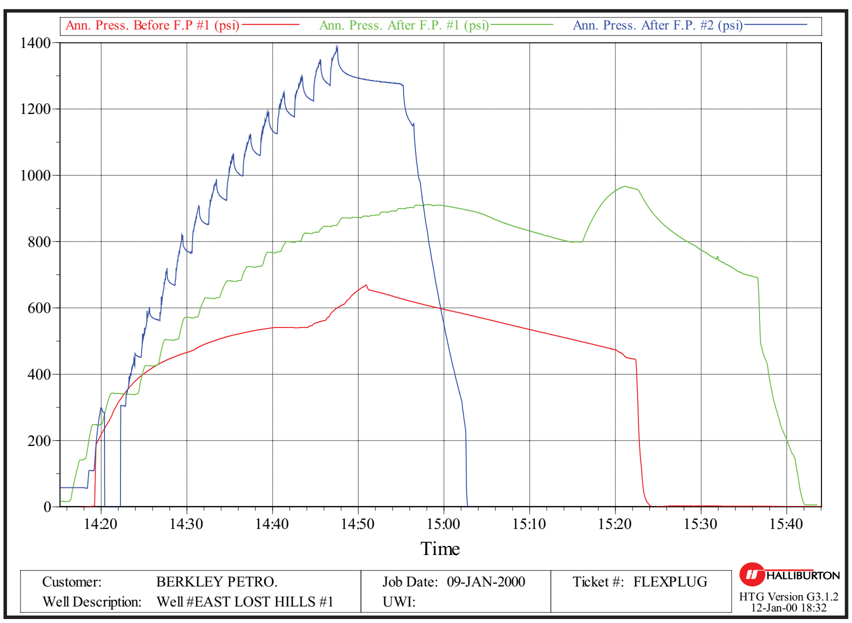

FIGURE 8.24: LOT AND FIT BEFORE AND AFTER DVC JOBS

psi and 300 F at 14,239 TVD. Pay zones in open holes have been sealed during drilling without impairment of production after installing cased-hole completions due to the agglutinates having almost zero fluid loss and less than 1/8" penetration in darcy permeability core tests. Figure 8.24 is one example of successful DVC system treatments in long hole sections where production was not impaired by DVC squeeze jobs in production zones as reported in SPE 71390 (Webb, 2001).

Figure 8.24 shows how DVC systems increase wellbore integrity as shown in the before and after LOT and FIT data. The red curve (psi) is the initial LOT, the green curve (psi) is the LOT after the first DVC squeeze treatment, and the red curve (psi) is the FIT after second DVC squeeze treatment.

The following publications have more technical data, placement techniques, and case histories on DVC jobs: SPE papers 37671, 59059, 68946, 81413, 84318, 87094, 96420 and the March 2007 issue of SPE Drilling and Completions Journal.

Hesitation Squeezing Before Bumping the Plug on Primary Cementing Jobs

Challenging Shoe Tests

Poor shoe test success rates for LOT and FIT can result from the lack of mud removal at the shoe because of wellbore washouts or a gelled and immobile drilling fluid.

Proposed Solution

Perform a hesitation squeeze just before the end of the primary cement job on all casing shoes (no liners) where a LOT or FIT pressure integrity test will be conducted. Hesitation squeezing at the end of the primary job has been identified as a potential method to help improve LOT/FIT results. Hesitation pumping may also act to delay the onset of the cement slurry transition time, thus aiding in the prevention of annular gas migration through the unset cement column. Even though a general procedure is provided below; volumes, shutdown times, and pump rates should be adjusted based on experience, job conditions, slurry thickening time and slurry type (i.e., thixotropic versus delayed gel cement slurry designs).

Field Test Results

Hesitation squeezing at the end of primary cement jobs to improve LOT/FIT results has been performed on an infrequent basis and with mixed results by some operators. However, other operators successfully perform this procedure on a regular basis. This discrepancy in reported results is largely due to poor or inappropriate application of the method. Findings show that when conducted properly, hesitation squeezing can contribute to LOT/FIT values being more in line with the expected values. Along with helping to remediate poor mud removal at the casing shoe, another potential benefit of hesitation squeezing is that wellbore pressure containment may be favorably affected in the sense of increasing the near wellbore hoop stresses.

Cement slurries can be designed to greatly reduce the risk of annular gas migration through unset cement. However, there are instances where nuisance gas formations were not apparent at the time of slurry design. Low-rate pipe movement and annular pressure pulsing after cement placement have both been documented as offering some degree of reduced risk of annular gas migration. However, there are many situations where these operations are not possible. Similar disturbance to the cement gel strength formation can also be accomplished by a hesitation pumping procedure.

Procedure

1. Displace cement as usual at maximum permissible rates predicted by ECD vs. FG simulations.

2. When 500 ft or 50 barrels of displacement remains (whichever occurs first), quickly slow pumps down to 1.0 bbl/min. Maintain rates at 1.0 bbl/min until pump pressure and annular returns are steady.

3. Stop pumping. If the reported slurry thickening time is more than twice the actual job time, wait at least 30 minutes. If the slurry is thixotropic, remain static for its reported delayed gel time (usually reported as the time to reach 100 lb/100 sq ft of gel strength).

4. Resume pumping at 1 bbl/min and pump 15% of the remaining volume. If the pump pressure does not increase to 1.5 times more than was measured at 1.0 bbl/min prior to the initial shut down, repeat the waiting period. If pressure is substantially higher, continue pumping until 50% of remaining volume is displaced. If pressure is not steadily increasing after 50% has been pumped, stop pumping and repeat the waiting period for half the duration of the first shut down.

5. Repeat this procedure until displacement is complete or the maximum pressure has been reached.

Avoiding Poor Placement of Squeeze Cement in Some Deviated and Horizontal Wellbores

Challenging Squeeze Placement

During high-pressure squeezes in most vertical wells, single fracture planes are initiated and propagated with enough cement slurry to achieve the desired squeeze pressure as shown in the top wellbore in Figure 8.25 where the entire fracture intersects a vertical interval in the wellbore. The same happens in deviated and horizontal wellbores when the maximum horizontal stress (σ_{Hmax}) is aligned with the wellbore azimuth as depicted in the far left wellbore in Figure 8.25. However, many deviated and horizontal wellbores don't align with σ_{Hmax} as illustrated in the other three wellbores in Figure 8.25. The latter condition can substantially reduce the length of the wellbore interval that intersects with the fracture. This decreases the flow area into the formation fracture that the squeeze cement slurry must travel and likely prevents slurry flow into some adjacent perforations that don't intersect with the fracture.

Placement Solution

A high-pressure, hesitation squeeze procedure can help divert the cement slurry flow to the bypassed perforations that don't intersect with the initial fracture. Many variations of this squeeze procedure may be used depending on well conditions and a pre-job injection test with a retrievable washing tool (opposed cups or inflatable elements) into the perforations during the perf-washing operation. Pre-squeeze washing of the perforations is recommended to remove mud solids and other plugging materials from every perforation tunnel. A retrievable squeeze packer is then set above the perforated interval and an injection test is run to initiate a fracture. After a designed volume of slurry (1st stage) is pumped into the initial fracture, the tool is cleared and the job is shut down long enough for the slurry gel strength to increase and/or dehydrate into filter cake to prevent further flow into the initial fracture. An injection test is repeated to confirm that the bypassed perforations will accept flow of fluids. Another volume of squeeze slurry (2nd stage) is then circulated down and squeezed into a newly created fracture that interests with some of the bypassed perforations. The steps done after placement of the 1st stage are repeated. Other stages of slurry are run until the desired squeeze pressure is obtained. A negative pressure test, called an in-flow test, is often run to confirm that all the perforations are sealed by cement.

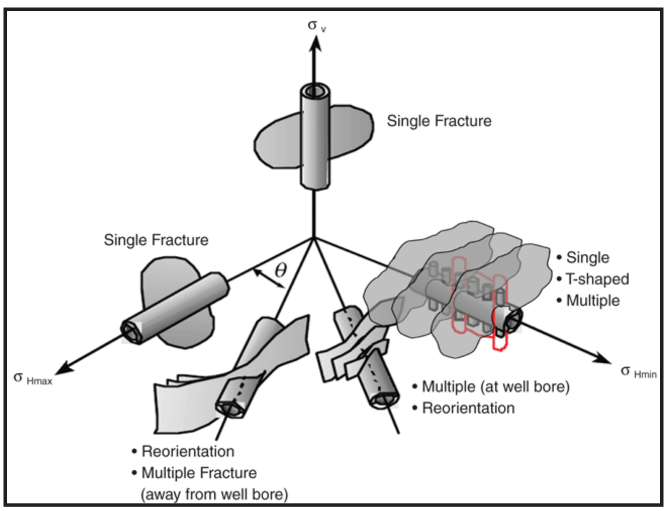

FIGURE 8.25: WELLBORE INTERSECTION WITH FRACTURES

ANSWERS TO UNIT QUIZZES

Items from Unit A Quiz	Refer to Page
1. correct, fill, oil/water	136
2. dehydrates	137
3. fracturing, pump-in, fluid	137
4. high	137
5. bleed-off, hesitation	137-138
6. maximum	138
7. fluid-loss	138

Items from Unit B Quiz	Refer to Page
1. Drillpipe size Packer depth Top of perforations Bottom of perforations Casing size	139
2. yield of the slurry	140

CHAPTER 9

SURFACE CEMENTING EQUIPMENT

TABLE OF CONTENTS

INTRODUCTION

A key factor for successful cementing operations is the use of cementing wiper plugs to separate cement slurries from drilling fluids present in the well and from displacement fluids that follow the cement. Cementing heads on surface and plug container systems are the devices required to deploy cementing wiper plugs.

The main purpose of cement mixing systems is to blend water and dry cement at satisfactory rates so that ideal densities (weights) and viscosities are pumped into wells to help properly place and set the cement downhole. Density meters and sensors on surface are the devices required to control and provide the designed cement densities in the well.

Topic Areas

In this chapter, the following units are included:

A. Cementing Heads/Plug Containers

B. Density Measurements

Learning Objectives

The objective of this section is to become familiar with the following:

- Types of cementing heads;
- Use of density meters and sensors.

UNIT A: CEMENTING HEADS & PLUG CONTAINER SYSTEMS

Plug containers, also called cementing heads, are used in most cementing jobs to adapt the casing to the pump as well as release the cementing plugs at the proper time. Cementing plugs, also called wiper plugs, are used to separate wellbore fluids and cement slurry. The plug containers are designed to hold one or two plugs that can be loaded before mixing the cement slurry.

Plug containers are installed on top of the casing before cement jobs to allow operators to drop the top cementing plug without opening the casing. When continuous circulation of the well is not required in some cementing situations, single plug heads can be used by stopping the pumps long enough to open the casing and insert the bottom plug into the casing. After re-installing the cementing head and pumping the cement slurry, the pumps are again stopped to drop the top plug from the single plug container.

Continuous circulation of the well may be required during cementing operations to prevent issues such as stuck casing or other unwanted hole conditions. By stacking plug containers or using double plug containers, wells can be constantly circulated with some types of cement heads, flow manifolds and plug release mechanisms. Otherwise, only short shut downs are needed to drop the plugs.

Plug containers have advantages over the other plug dropping methods:

- Plugs may be loaded in a container before the mixing of the cement slurry;
- Plugs may be released from some types of containers at any time without interrupting the pumping operation;
- No air enters the pipe (as would be the case with a swage), so the prospect of introducing channeling due to entrained air is reduced;
- Plug containers eliminate the job shut down time spent removing a swage to drop a plug.

Plug containers are available in two types: free-fall and manifold. Cementing plugs fit loosely in the free-fall plug container and rely on gravity to pull the plug down into the fluid flow stream, allowing the plug

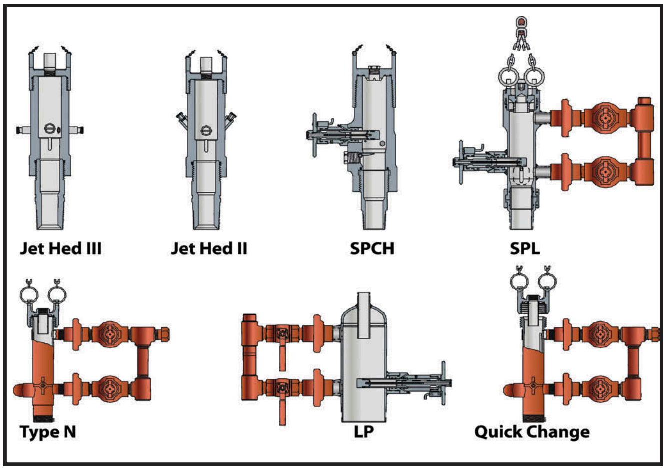

FIGURE 9.1: VARIOUS TYPES OF PLUG CONTAINERS.

to be pumped downhole. Manifold plug containers allow fluid to be diverted above the plug for positive plug release.

Methods of Using Plug Containers

Non-Continuous Circulation

To use a plug container on non-continuous pumping jobs, follow the guidelines below:

1. Stop circulating the well fluids and remove the plug container cap;
2. Insert the bottom plug through the plug container to a point just below the inlet port;
3. Move the plug-release plunger to the extended position;
4. Place the top plug inside the plug container so that it rests on top of the extended plunger;
5. Reinstall the cap on the top of the plug container and begin the cementing job. The bottom plug will travel down the casing in front of the cement to separate the cement from the well fluid;
6. Release the top plug at the proper time by moving the plug release plunger into its retracted position. The top plug then follows the cement down the casing to separate the cement from the displacing fluids.

Continuous Circulation

If well conditions dictate that continuous circulation be used, use two plug containers or a double plug container as described below:

1. Load both plugs into the plug container before circulating the well fluids so that both plugs can be released without opening the plug container;
2. Circulate the well fluids and prepare the cement for pumping;
3. When the cement is introduced into the casing, retract the bottom plug release plunger for the bottom plug;
4. Open the middle valve (Figure 9.4) above the bottom plug to allow the bottom plug to enter the casing ahead of the cement;
5. At the proper time, release the top plug by retracting the top plug release plunger, which is holding the plug inside the plug container;
6. Open the top valve (Figure 9.4) above the top plug. The top plug then follows the cement and separates it from the displacement fluid.

Commonly Used Containers

The example plug container shown in Figure 9.2 has some advantages when compared to older style conventional plug containers. Offset fluid entry ports create a vortex inside the plug container to pull the plugs into the fluid stream at the proper time. A looser fit also helps ensure more reliable release of the plug from the plug container. Other improvements include a high-pressure rating from better manifold connections, improved welds, and a one-piece cap for more reliable operation. These plug containers can be remote controlled to reduce the risk of accidents.

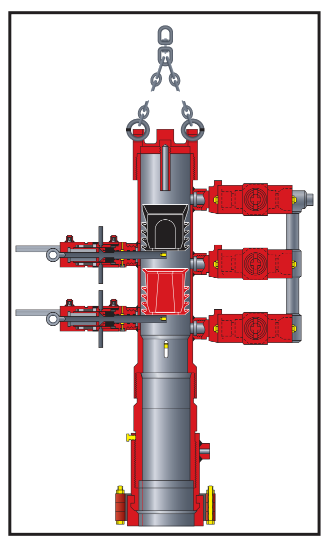

FIGURE 9.2: EXAMPLE OF A STANDARD PLUG CONTAINER.