EEI ENGINEERING ENTERPRISES, INC.

This technical assistance document has been prepared for USEPA Headquarters located in Washington, D.C., and is funded under LOE Contract No. 68-03-3416, Work Assignment No. 2-0-21. The USEPA Work Assignment Manager is currently Mr. Jeff Smith. The USEPA LOE Project Officer is Mr. Robert Smith.

The objective of this work assignment is to provide EPA with a technical document which presents and discusses proper cementing practices for the permanent plugging and abandonment of injection wells. This guidance has been prepared as part of the Mid-Course Evaluation (MCE) effort and will assist EPA Regions in the evaluation of plugging and abandonment plans and procedures, as well as cementing practices currently being utilized by operators of Class II wells.

Work Assignment Manager: Janet K. Pearce
Janet K. Pearce

Project Manager: J.L. Gray
J.L. Gray

UIC Program Director: Talib Syed
Talib Syed

President: John Fryberger /JLG
John Fryberger

TECHNICAL ASSISTANCE DOCUMENT:

CEMENTING FOR THE PLUGGING AND ABANDONMENT OF INJECTION WELLS

PREPARED FOR

U.S. ENVIRONMENTAL PROTECTION AGENCY

HEADQUARTERS - WASHINGTON, D.C.

PREPARED UNDER

EPA CONTRACT NO. 68-03-3416

WORK ASSIGNMENT NO. 2-0-21

PREPARED BY

ENGINEERING ENTERPRISES, INC.

NORMAN, OK

SEPTEMBER, 1989

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Acknowledgments

The following persons are responsible for this technical assistance document:

Engineering Enterprises, Inc.

Authors:	Ms. Janet Pearce
	Mr. J.L. Gray
Work Assignment Manager:	Ms. Janet Pearce
Project Manager:	Mr. J.L. Gray
Sr. Technical Advisor:	Ms. Mary Mercer
UIC Program Director:	Mr. Talib Syed
President:	Mr. John Fryberger

U.S. Environmental Protection Agency Headquarters

Work Assignment Managers:	Mr. Jeff Smith
	Mr. Mario Salazar
LOE Project Officer:	Mr. Robert Smith

Appreciation is also extended to Ms. Kim Howland and the support staff at EEI for their many hours spent in the preparation of this report.

In addition to the above, Engineering Enterprises, Inc. would like to acknowledge industry personnel, service companies, and professional organizations for their contributions to available technical literature, which was utilized extensively in preparing this guidance document.

1.0 INTRODUCTION

1.1 BACKGROUND

The U.S. Environmental Protection Agency (EPA) is required by the Safe Drinking Water Act (SDWA) of 1974, as amended, to implement the Underground Injection Control (UIC) program. The objective of the UIC program is to protect underground sources of drinking water (USDWs) from contamination resulting from underground injection practices.

The UIC program regulates the injection activities associated with all classifications of injection wells. Since this report is part of the Mid-Course Evaluation (MCE) effort, emphasis is placed upon Class II wells, consisting of those wells which inject fluids: (1) brought to the surface during oil and gas production (Class IID, or disposal); (2) for the enhanced recovery of oil and gas (Class IIR, or recovery); and (3) for liquid hydrocarbon storage (Class IIH). However, plugging procedures described herein are applicable to all well classes.

The EPA UIC plugging and abandonment (P&A) regulations for Class II wells are found in 40 CFR, Part 146.10. These regulations state that:

(1) The well shall be plugged with cement in a manner which will not allow the movement of fluids either into or between USDWs;

(2) Placement of cement plugs in the wellbore shall be accomplished by the: (a) balance method; (b) dump-bailer method; (c) two-plug method; or (d) an alternative method, approved by the Director (Regional or State), which will reliably provide a comparable level of protection to USDWs; and

(3) The well to be abandoned shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director, prior to the placement of the cement plugs.

In accordance with 40 CFR, Part 146.24 (d), prior to granting approval for the P&A of a Class II well, the Director shall consider: (1) the type and number of plugs to be used; (2) the placement of each plug; (3) the type, grade, and quantity of cement to be used; (4) the method of plug placement; and (5) the procedure used to establish static equilibrium in the well to be plugged.

There have been at least two reported cases which indicate the use of inadequate cementing practices in the plugging of injection wells. Although the UIC regulations cited above require adequate plugging of Class II injection wells, they do not specify acceptable criteria regarding cement types, plug locations, cement mixing and placement techniques, etc. The main objective when plugging a well for abandonment is to prevent interzonal communication and the migration of fluids that might infiltrate and contaminate USDWs. In order to accomplish this objective, proper cementing techniques must be used.

1.2 PURPOSE

The purpose of this technical document is to present and discuss proper cementing practices for the permanent plugging and abandonment of injection wells. The document will provide technical assistance to EPA Regional personnel involved in the evaluation of plugging and abandonment plans and procedures submitted by operators of Class II injection wells.

1.3 SCOPE

This document presents a discussion on the proper cementing practices utilized in an injection well plugging and abandonment operation. The information which is presented was obtained from professional publications, text books, and EPA technical assistance manuals pertaining to cementing practices recommended for the permanent plugging of injection wells. The following provides a summary of major topics covered in this report:

(1) Considerations in Plugging Job Design;

(2) Well Preparation Prior to Plugging;

(3) Selection of a Plugging Fluid;

(4) Cement Types and Additives;

(5) Selection of a Cement Slurry;

(6) Proper Cement Mixing Methods; and

(7) Cement Plug Placement and Testing Methods.

2.0 INJECTION WELL PLUGGING AND ABANDONMENT

2.1 ENVIRONMENTAL CONCERNS

EPA UIC regulations state that the plugging and abandonment of a Class II injection well must ensure that the well is plugged with cement in a manner which will not allow the movement of fluids either into or between USDWs. In order to achieve a successful plugging operation, provisions must be made for long-term protection against the migration of formation and/or injection fluids into USDW horizons.

The plugging practices and cementing methods utilized during the abandonment operation can result in significant environmental problems if not performed properly or sufficiently. The improperly plugged wellbore acts as a potential conduit for fluid movement into USDW horizons. This is clearly illustrated in the various reports of old, abandoned wells, which, according to numerous sources, have been known to contribute to USDW contamination. Such old wells were plugged under conditions which were considered acceptable at the time of abandonment. The cause of vertical fluid movement in these old, abandoned wells is often attributed to an increase in reservoir pressure brought about by secondary recovery operations which simply were not considered at the time of abandonment. Although significant advances have since been made in plugging and abandonment technology, there continues to be a need for greater care in both plugging job design and execution.

In order to accomplish the objectives set forth above, the abandonment process must be thoroughly planned prior to initiation of the actual field operation. Ideally, plugging and abandonment operations are designed to ensure the ultimate integrity of the wellbore to be plugged. In general, plugging for abandonment purposes is successfully accomplished through the emplacement of one or more effective cement plugs set through selected depth intervals.

2.2 BASIC CONSIDERATIONS FOR PLUGGING JOB DESIGN

An effective P&A plan must address all aspects of the abandonment process and incorporate a variety of factors into the plugging job design. In generating the P&A plan and procedure, consideration must be given to the: (1) geological environment of the well; (2) existing mechanical conditions of the well; and (3) equipment availability and expense.

Each of these items will affect the plugging job design and should, therefore, be evaluated thoroughly before determining specific procedures for well preparation and subsequent plugging. As is evident by the variety of plugging procedures available, each well must be evaluated individually so that the most appropriate materials and procedures can be selected for its particular circumstances. The following sections provide a brief discussion of each of the above considerations.

2.2.1 Geological Environment

Prior to the development of plugging job design, the well's geological environment should be known. Underground sources of drinking water and any potential producing or lost circulation zones should be identified so that appropriate actions can be taken during the abandonment operation.

2.2.2 The Mechanical Condition of the Well

Careful examination of the mechanical condition of the injection well plays an important róle in determining whether or not remedial actions may be necessary to ensure the effectiveness of the plugging operation. If an injection well lacks casing or cement integrity, then there already exists a potential for vertical fluid migration. Such a condition must be addressed prior to attempting to place cement plugs in the well.

Other mechanical conditions of the well must be considered for job design purposes. For instance, there may be equipment which cannot be retrieved from the well due to damage which has occurred in the past (e.g. stuck tubing, collapsed casing, etc.). In such cases, the operator must be prepared to utilize alternate plugging methods which will assure adequate protection to USDWs.

2.2.3 Equipment Availability and Expense

Decisions made during the development of an abandonment plan are generally made with regard to expense and availability of equipment. In many cases, decisions concerning a particular aspect of the abandonment process involve a choice between various materials and/or methods used to accomplish the same basic objectives. An evaluation for each individual situation should be performed to weigh the costs of using specific materials and/or methods against the relative benefits each might offer to the overall plugging operation.

Equipment availability is certainly another factor which must be considered when planning a well's abandonment. Prior to specifying a plugging procedure, the operator must be sure that any necessary workover equipment is readily available to fulfill the requirements set forth in the P&A plan.

2.3 IMPORTANT POINTS

INJECTION WELL PLUGGING AND ABANDONMENT

1. ENVIRONMENTAL CONCERNS

- Prohibit movement into or between USDWs
- Unplugged or improperly plugged wellbore is potential migration conduit
- Documented cases of USDW contamination via abandoned wells
- Successful abandonment = one or more cement plugs through selected intervals
- Operational concerns also

2. BASIC CONSIDERATIONS FOR PLUGGING JOB DESIGN

- Define Geology
  - USDWs
  - Potential producing zones
  - Lost circulation zones
- Ascertain Mechanical Condition of Well
  - Casing integrity
  - Cement integrity
  - Junk in hole
  - Stuck tubing
  - Collapsed casing
  - Remedial action necessary?
- Equipment Availability and Expense
  - Workover rig
  - Access to location
  - Fishing tools
  - Cutting and milling tools
  - Service companies
  - Wellbore fluids

3.0 EXECUTION OF THE PLUGGING OPERATION

3.1 MAJOR PLUGGING ACTIVITIES

Plugging for abandonment consists of two major phases: (1) well preparation; and (2) well plugging. Well preparation, as the term implies, consists of those activities necessary to prepare the wellbore for effective plug placement and final abandonment. Such activities may include: (1) inspection of well conditions; (2) removal of tubing, packer, and/or salvageable casings; (3) remedial operations such as fishing, milling, squeeze cementing, or plug-back operations; and (4) establishment of static equilibrium.

Well plugging consists of those activities associated with the placement of cement and/or mechanical plugs at designated positions within the wellbore. Although there are several cement plug placement methods available, the most common methods involve pumping the cement slurry through a string of drill pipe or tubing.

The plugging job design and abandonment procedures which may be selected for an individual injection well are dependent upon the construction characteristics of that well immediately prior to abandonment. Several common injection well construction types are presented in Figures 3-1 through 3-3. In order to illustrate the stages involved in plugging and abandonment operations, each well construction type is depicted in its state prior to well preparation, after well preparation, and after well plugging and final abandonment.

WELL CONSTRUCTION TYPE A
STAGES OF ABANDONMENT

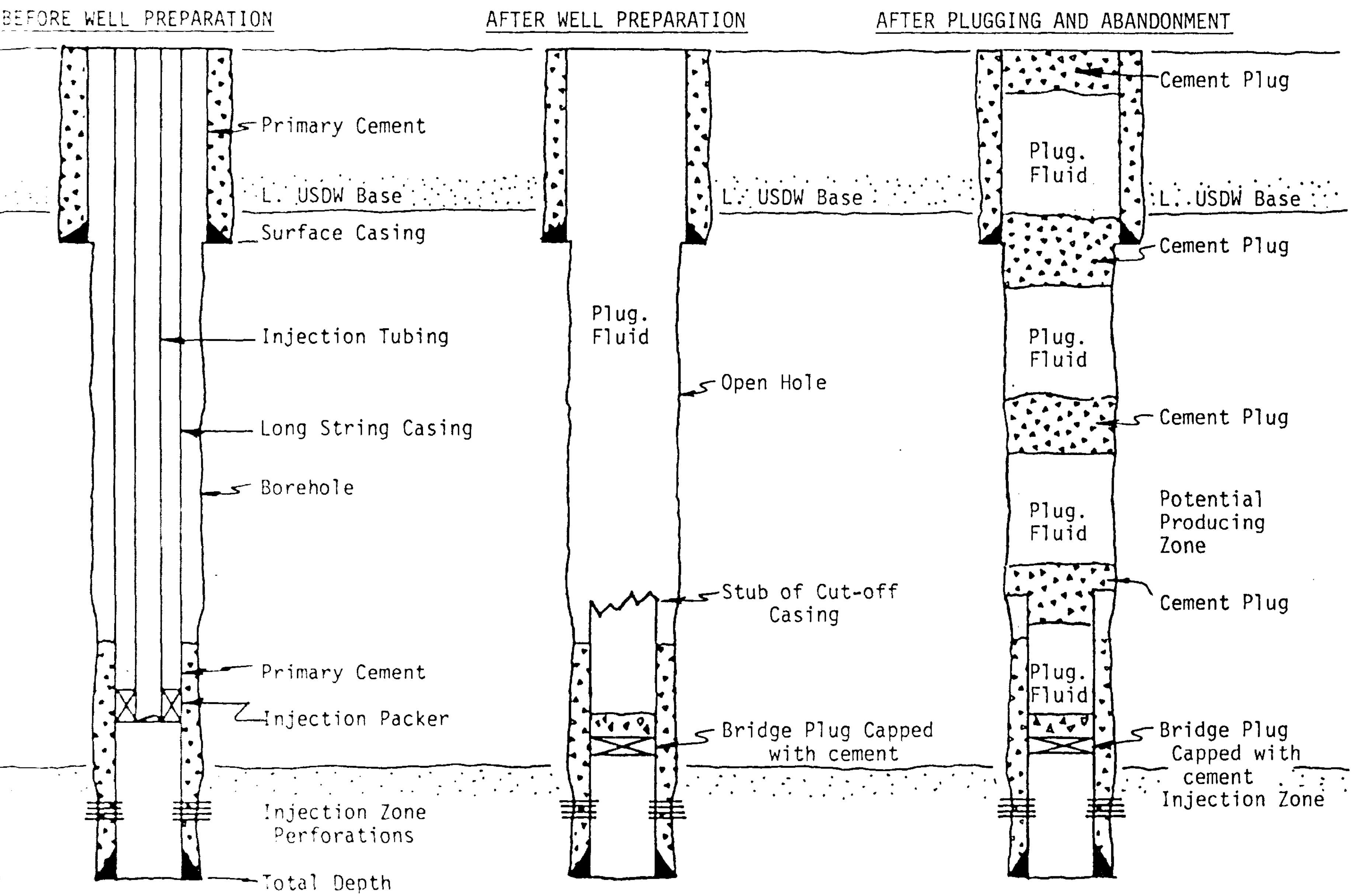


FIGURE 3-1

WELL CONSTRUCTION TYPE B
STAGES OF ABANDONMENT

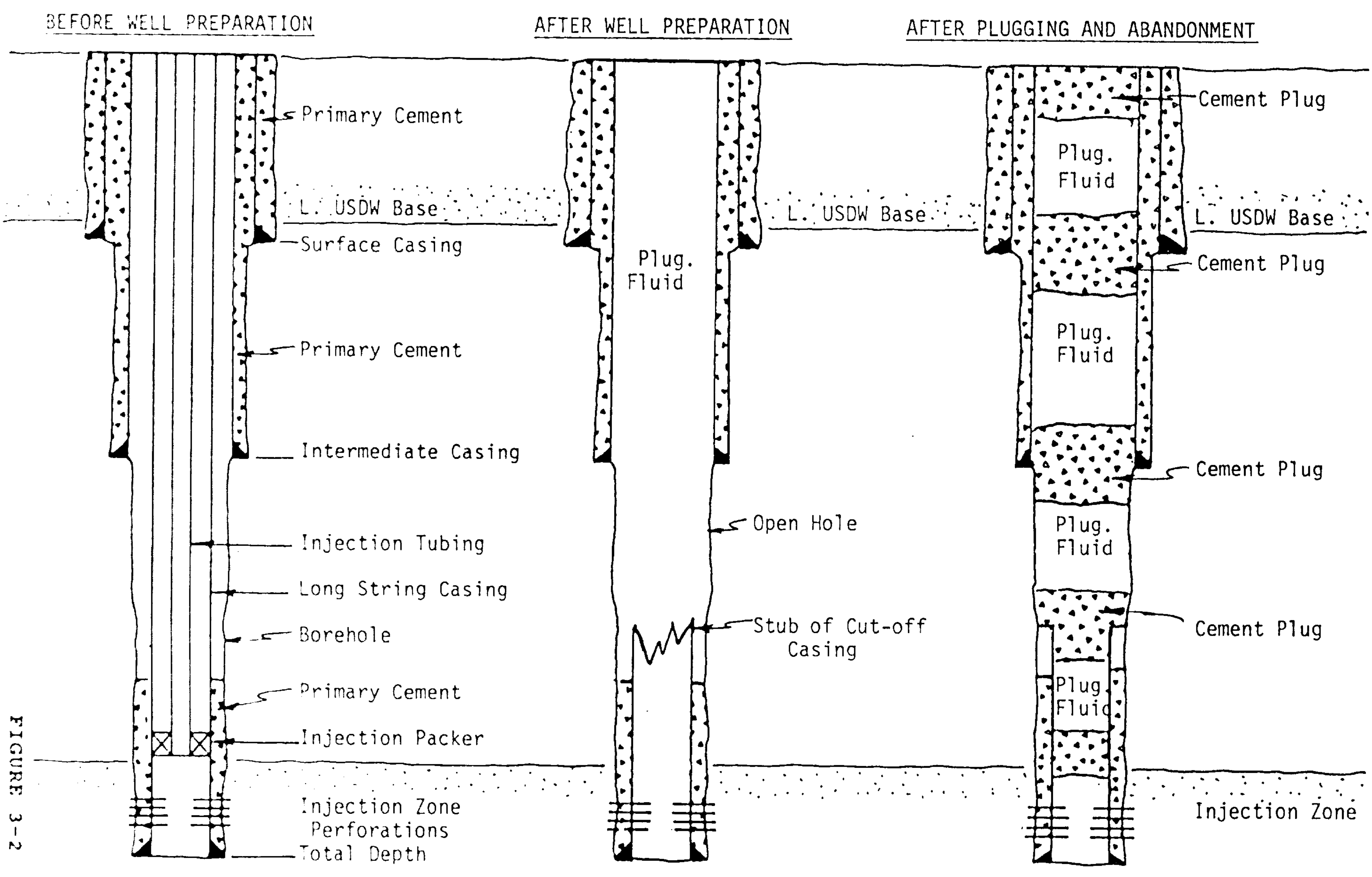


FIGURE 3-2

WELL CONSTRUCTION TYPE C
STAGES OF ABANDONMENT

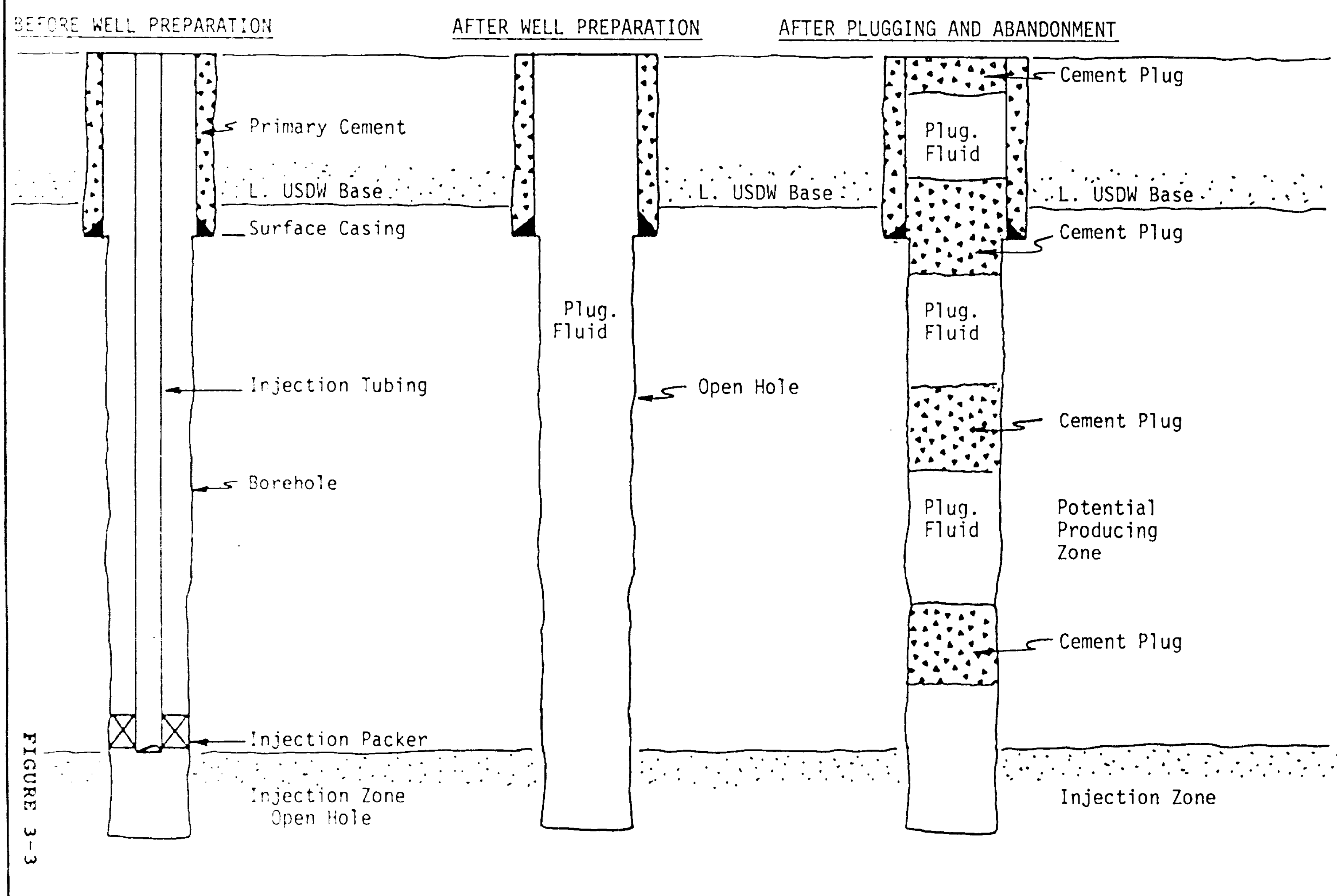


FIGURE 3-3

3.2 WELLBORE PREPARATION

In any plugging operation, care must be exercised in preparing the wellbore for cementing to ensure that effective cement plugs result. Wellbore preparation not only involves activities necessary to ensure a proper environment for setting plugs, but also includes those activities associated with the basic integrity of the well. These activities are essential to achieving an abandonment that will provide long-term prevention of fluid migration into USDWs. As stated earlier, wellbore preparation activities include: (1) inspection of well conditions; (2) removal of downhole equipment; (3) remedial operations; and (4) establishment of static well conditions. Inherent to wellbore preparation activities is the selection of appropriate plugging fluids (Refer to Section 4.0).

3.2.1 Inspection of Well Conditions

The first step in the abandonment process entails an investigation of available records in an effort to determine the construction characteristics of the well, and to become familiar with local geology. Knowledge of well construction and geological environment is essential to the abandonment design process.

Construction details which must be considered during wellbore preparation include: (1) size, grade, and setting depth of casing strings; (2) cementing programs used to install casing strings; (3) injection tubing and packer configurations;

(4) perforations or open-hole sections of the well; and (5) any other mechanical equipment (or cement) that may be present in the well prior to abandonment (e.g. packers, cement plugs, etc.).

Much of the required well construction data can be derived from permit applications, well completion reports, workover records, and operating and monitoring reports.

Additional consideration must be given to construction-related factors that might influence the plugging procedure or long-term integrity of the abandoned well (e.g. casing leaks, corroded or collapsed sections of casing, and cement channeling). Such potential deficiencies in mechanical integrity may be discovered through a simple review of well records or through conventional mechanical integrity testing methods.

The standard annular pressure test can be used to determine the existence of casing leaks, while a temperature survey, casing inspection log, or caliper log can be used to identify the location and extent of such leaks. Annular cement quality can be examined by using a radioactive tracer survey, cement evaluation log, or noise log. The use of specific investigation methods will depend largely on the anticipated condition of the individual well to be plugged. Decisions regarding the need to perform such construction-related investigations should be made accordingly.

Sufficient information concerning site-specific geological conditions must also be obtained to determine the location and characteristics of USDWs, as well as the formations separating them. Examination of the geological characteristics and pressures encountered in the injection zone and overlying formations also plays an important role in the well preparation process. Such geologic information provides much of the basis for determining: (1) plug type, location, and height; (2) cement slurry and wellbore fluid system design; and (3) casing removal programs. The identification of corrosive zones and injection fluid/formation fluid constituents is also an important part of the planning process, particularly in regard to determination of an appropriate cement slurry. Geological and hydrogeological data can generally be derived from well records, geophysical well logs, or geologic studies.

3.2.2 Removal of Well Equipment

The removal of well equipment is a preliminary step that will influence the overall plugging and abandonment operation. Before removing any equipment from the well, it is necessary to evaluate the impact that such action might have on the effectiveness of abandonment procedures.

Injection tubing is almost always removed from the well prior to plugging. Tubing serves no practical purpose after abandonment and can inhibit downhole activities. In addition, injection tubing can often times be salvaged and retained for future reuse.

Associated with the decision to remove injection tubing is the decision regarding whether or not the injection packer should be removed. Many injection packers are readily retrievable, while others are considered permanent installations. Retrievable packers can generally be reused (after minor repairs are made). The recovery of a permanent packer, however, is usually not attempted due to the expense of the operation. Permanent packers must be drilled up with a milling tool.

The removal of tubing and packer involves setting up a workover rig, unsetting the injection packer, and pulling the injection string out of the hole. Depending on the specific steps outlined in the P&A plan, it is not uncommon to utilize this preliminary step as an opportunity to establish the wellbore plugging fluid system. For instance, operators may unset the injection packer and circulate a clean plugging fluid throughout the wellbore prior to removal of the injection tubing/packer configuration. This operation aids in cleaning the well and, in some instances, can save the operator time and expense.

Selection of an appropriate workover rig is generally dictated by lifting requirements. Deeper wells which contain more pipe and consequently, more weight, will usually require larger rigs that are capable of supporting the additional weight. The majority of all workover rigs are equipped to: (1) pull the tubing (or casing) string; (2) rotate pipe while in the hole; (3) stand pipe in the derrick; and (4) circulate fluid(s) throughout the wellbore (Petroleum Extension Service, 1979). However, in some oil-producing areas with relatively shallow reservoirs (e.g. Illinois, western Kentucky, Ohio and portions of the Appalachian Basins), cable tool rigs are utilized to perform workover and plugging operations. In order to be able to rotate pipe and circulate fluids, these rigs must be specifically equipped with auxiliary equipment such as hydraulically-operated power swivels and duplex or triplex mud pumps.

If tubing and/or packer cannot be successfully removed from the well, the unstuck portion of the tubing string can be severed above the packer and removed. Should the operator desire to remove the portion of tubing and the packer remaining in the hole, each can be drilled up with a mill, and the debris circulated out of the hole. In such instances, however, the operator may be able to satisfy regulatory P&A requirements by setting a mechanical and/or cement plug above the severed tubing string.

The removal of screens or liners set across the injection interval may be required in some areas. Although salvaged screens and/or liners are generally of little economic value, some state regulatory agencies may prefer their removal to enhance plug placement across the injection zone.

Another decision that must be made concerns the removal of casing from the well. It is not uncommon to find intermediate and/or long string casings which are only partially cemented in place (i.e. cement does not extend to surface). In most cases, it is desirable to attempt to cut and salvage the uncemented portion of the casing string. This decision, however, should be made only after careful consideration of a well's individual circumstances and the potential outcome of the casing recovery attempt.

Uncemented casings which remain in the well after abandonment may result in future problems. **This cannot be over emphasized!** By allowing the annulus around the casing to remain uncemented, there exists a conduit through which vertical fluid migration into USDWs can occur. In these cases, fluids could escape through a poor primary cement column or could migrate from pressurized formations exposed in the casing annulus. In order to avoid such a risk, the operator may be required to squeeze cement behind portions of uncemented casings which are to remain in the wellbore. Individual circumstances such as fluid gradients, local geology, etc. will dictate whether or not this is necessary to prevent vertical fluid migration.

The removal of uncemented portions of a well's casing may affect the plugging procedures used during abandonment. For instance, the removal of casing will result in the exposure of open hole sections within the well. The existence of any low or high pressure zones can affect subsequent attempts to establish static well conditions prior to setting cement plugs.

Uncemented portions of casing strings can be removed prior to plug-setting activities, depending on the specific circumstances of the injection well undergoing abandonment. However, difficulties may arise when running plug-setting tools into the open hole and then back into the lower portion of the casing string left in the well. Many operators and/or regulators prefer that required plugs be set inside the lower portion of casing prior to cutting and pulling the upper portion.

Before casings can be cut and retrieved, a free-point indicator tool is run inside the casing to determine its free point (i.e. where it can be severed). Tools used in casing cutting operations consist of high pressure fluid jet, chemical, mechanical, or explosive cutting devices. Selection of the most appropriate cutting tool will be influenced by casing characteristics, mechanical condition, and internal/external accessibility.

3.2.3 Remedial Operations

Prior to plugging a well, a variety of remedial operations may be required to successfully gain access to the intervals which are to be plugged. Remedial operations associated with plugging and abandonment may include: (1) well cleanout activities such as "fishing" or milling; (2) casing repair work such as squeeze cementing; or (3) plug-back operations.

Well Cleanout Activities

During the abandonment of an injection well, it may be necessary to remove obstructions from the wellbore in order to effectively emplace mechanical or cement plugs. Such obstructions can consist of materials ranging from small particles (e.g. sand) to large objects (e.g. packers or tubulars which have been dropped or stuck). Small particles, such as sand, formation cuttings, etc. can generally be removed through circulation of a workover fluid. Produced saltwater or bentonite muds (gels) are the most commonly used workover fluids. Any small objects such as metal pins, tools, or cuttings can be retrieved through the use of a junk basket retriever. A typical junk basket retriever is a circulation device which is able to catch small pieces inside its cylindrical barrel. Another tool which can be used to retrieve small metallic objects is a "fishing" magnet.

For large objects such as packers, tubing, etc. which may be stuck in the well, a variety of retrieval methods may be used. If the top of the pipe is free and is burred or split, a milling device can be used to smooth the top of the pipe. Once the top of the pipe is smoothed, an overshot tool can be lowered over the pipe and than rotated to cause the tapered inside of the tool to engage the pipe (Geraghty and Miller, Inc., 1982).

Recovery of pipe can also be accomplished by using a spear, which is a tapered tool that is lowered inside the pipe. Once the spear is positioned within the pipe string, several mechanical wedges are released or the tool housing is expanded to engage the pipe for removal.

Although fishing techniques are often successful in removing debris, an alternative method of equipment removal consists of milling and/or drilling.

Casing Repair

A second type of remedial operation that may be performed prior to the abandonment of an injection well is casing repair work. Repair of a damaged casing string is sometimes necessary as a means of access to a zone to be plugged. If the lower part of the hole cannot be reached due to collapsed or buckled casing, a casing roller or swaging tool can be used to open up the tight place in the casing. Another type of casing repair involves cutting and pulling undamaged casing. Once casing has been cut off, it is useful to grind down or bevel the severed edge to avoid any problems that may occur during plug-setting operations.

The most common type of casing repair is squeeze cementing, which involves the placement of cement slurry across a perforated or leaking section of casing. Hydraulic pressure is then applied to force the slurry against and into exposed formations. As mentioned earlier, squeeze cementing may also be deemed necessary for uncemented portions of casing which are to remain in the well after abandonment. In these instances, circulation squeeze cementing may be used to ensure that all of the annular void space is filled.

Circulation squeeze cementing entails circulation of the cement slurry in the casing annulus in an attempt to extend the cement height behind the casing. It is accomplished in one of two ways. The first method involves pumping cement into one set of perforations placed at the base of the proposed cement column. The cement is pumped under carefully monitored pressure conditions to prevent the hydraulic fracturing of formations exposed in the casing annulus (the calculated treating pressure at the perforations must not exceed the calculated hydraulic fracturing pressure for that particular depth). The second method involves two sets of perforations, one placed at the base of the proposed cement column and one placed at the top. This creates a permeable, low pressure channel through which the pumped cement can flow, thus, forming the desired annular cement column.

Plug-back Operations

Plug-back operations essentially involve plugging back lower zones from the upper portion of the well. In abandonment operations, this generally consists of setting a mechanical bridge plug above the injection zone (or other interval) exposed within the long string casing.

A number of plug-back operations are performed during the life of the well some time prior to plugging, thereby eliminating the need to perform such an operation during the well's abandonment. Although it is feasible to plug back lower zones in a well during the actual plugging process, it is usually more convenient to plug them back during well preparation. For instance, in cases where upper portions of long string casing are to be removed from the well during plugging, it is usually easier to set any injection zone plugs prior to casing removal. This technique may also enhance subsequent attempts to establish static equilibrium in the well.

3.2.4 Establishment of Static Well Conditions

Once well conditions have been assessed, necessary equipment removal and remedial operations are performed. Upon accomplishing these tasks, the well is ready for the final phase of well preparation. During this phase, fluids in the borehole should be brought to a static condition to ensure that fluid movement does not occur during the cement plug placement and setting processes. Any fluid movement in the wellbore during cement slurry placement and setting can result in contamination and/or migration of the cement slurry.

Static well conditions are established by controlling any flow, either into or out of the well. When a well is completely cased, this basically involves control of the injection zone pressure. In such instances, injection zone pressure and resultant flow can be controlled through: (1) circulation of a weighted plugging fluid; or (2) placement of a mechanical plug just above the pressurized interval.

In situations where casing has been removed from the well, fluid flow into and/or out of the well may result from formations exposed in the uncased portions of the hole. Static equilibrium, in these cases, can generally be accomplished through the use of a plugging fluid: (1) which has been specially weighted to overcome excessive formation pressures; or (2) which contains special materials designed to prevent lost circulation to low pressure formations.

Establishment of static well conditions is most readily accomplished through circulation of a new fluid system. The new fluid system will act not only to establish hydrostatic equilibrium in the borehole, but will also serve as the fluid remaining between cement plugs.

The main purpose of circulating the hole with a fresh fluid system is to ensure that the wellbore is in a static state. It is particularly important when setting cement plugs by the balance method. By filling the wellbore with a fluid of known and uniform density, the operator should be able to observe any changes in fluid weight caused by potential flow in the wellbore.

The second purpose of a new wellbore fluid system pertains to the condition of the borehole walls and the ability of the cement to bond to the hole and set up properly. For instance, in rotary-drilled wells, old drilling mud remains behind uncemented casings and mudcake may have formed on borehole walls. After casing is pulled, the open hole must be prepared to maximize cement bonding to the formation. This can be accomplished most efficiently by recirculating a fluid which is similar to the drilling fluid in weight and consistency. Additionally, chemicals may be introduced and/or wellbore scratchers (attached to the workover string) may be utilized for mudcake removal. If the wellbore is already in a static state, it is not always necessary to clean the entire borehole prior to cementing. Naturally, the most important portions of the hole are those across which cement is to be emplaced. Many operators may choose to pump a "spacer" fluid ahead of each cement plug. This fluid acts to ensure that the borehole walls are clean and that the cement slurry is preceded by a fluid which is compatible with its constituents (e.g. will not contaminate it). Section 4.0 provides a more detailed discussion of plugging fluids.

3.3 IMPORTANT POINTS

WELLBORE PREPARATION

1. **INSPECTION OF WELL CONDITIONS**

   - Well records/files
   - Size, grade, depth of tubulars
   - Primary cementing program
   - Condition of cement and tubulars
   - Perforations/open-hole
   - Downhole equipment
   - Formation pressure

2. **REMOVAL OF WELL EQUIPMENT**

   - First step
   - Requires workover rig
   - Tubing almost always removed
   - Some packers not retrievable
   - Cutting uncemented casing
     - Jet
     - Chemical
     - Mechanical
     - Explosive
   - Pulling casing
   - Fishing

3. **REMEDIAL OPERATIONS**

   - Well cleanout
   - Casing repair
   - Plug-back operations

4. **ESTABLISHMENT OF STATIC WELL CONDITIONS**

   - Prevents cement contamination
   - Proper fluid weight (well control)
   - Circulate at least one wellbore volume

3.4 WELL PLUGGING

3.4.1 Plug Types and Location

The plugs used in the plugging and abandonment operation include mechanical and/or cement plugs. Both are designed to isolate zones for the purpose of preventing: (1) USDW crossflow; (2) surficial flow; (3) contamination of USDWs by oil, gas, or brines; and (4) contamination or disturbance of other formations having potential value.

Mechanical plugs generally consist of permanent or retrievable bridge plugs. When used in abandonment operations, they are frequently placed in casing, either: (1) just above the injection zone; or (2) above any well equipment which is not retrievable (e.g. stuck tubing and/or packer). Mechanical plugs set above the injection zone (or other pressurized zone) can provide assurance that there will be no upward fluid movement from the zone. As a safety measure, 50 to 100 feet of cement should be placed on top of the plug.

Although mechanical plugs are commonly used to isolate a pressurized injection zone, cement plugs are the major constituents of an abandoned wellbore. The number and length of cement plugs will vary with the well depth, number of producing formations encountered, and the amount of casing left in the hole. Cement plugs are often placed: (1) above the lowermost production and/or injection zone; (2) above, below, and/or through each producing formation and each **fresh water strata**; (3) at the bottom of intermediate and surface casings; (4) across any casing stubs (pulled casing sections); and (5) at the surface. In relationship to the UIC program, critical containment points that should be isolated are the injection zone, the USDW base, and any point above the USDW base where water quality varies significantly.

A series of plugs separated by an adequate wellbore fluid is generally considered to be adequate protection. Most experts agree that placement of a continuous column of cement from the top to bottom of the well is not necessary to ensure the prevention of fluid migration. In most cases, any benefits that may be derived from the solid cement plug are not justified by the additional expense. However, there are situations where a continuous column of cement would be more economical than a series of plug. For instance, it is sometimes more economical to set a continuous column of cement in a shallow well rather than setting numerous plugs. The rig time and labor expenses incurred as a result of waiting for each cement plug to set up, etc. can be considerably higher than the expense incurred by the additional cement volume.

When selecting the number and length of cement plugs, the most important point to remember is that the plugs must be placed in a manner that will ensure that there is no direct communication between permeable, producing formations and USDW horizons. Regulatory requirements in regard to the number and length of cement plugs vary somewhat among states. Although required cement plugs may range from 25 to 200 feet in length, a 50-foot plug is considered to be a minimum in most cases.

3.4.2 Placement and Setting of Cement Plugs

The design and placement of the cement slurry is one of the most important components of the plugging and abandonment operation. As will be discussed further in Section 5.0, the placement of an effective cement plug requires careful planning and considerable skill. Caution must be used not only in designing the cement slurry itself, but in placing the cement slurry without contamination.

During the selection of a cement slurry, consideration must be given to borehole conditions such as temperature, pressure, potential lost circulation zones, and fluid compatibility. The cement slurry should be designed so that it can withstand long-term exposure to downhole conditions. Plugging fluids left between plugs should also exhibit stability over indefinite periods of time. Some drilling fluids, brines, formation fluids, and injection fluids can act to inhibit the setting properties of cement. Therefore, caution must be exercised in placing the cement slurry without contamination of the cement. The potential for cement contamination can be minimized by: (1) establishing and maintaining static well conditions prior to and during plug setting; (2) utilizing spacer fluids to separate the cement slurry and borehole fluids; and (3) cleaning casing and/or borehole surfaces prior to plug placement.

3.4.3 Testing of Cement Plugs

Testing of cement plugs is performed by "tagging," which consists of running pipe into the hole to locate the plug. After the cement has set up, the pipe is run into the hole to the plug depth and weight is applied to check the position of the plug. Cement plug tagging is discussed further in Section 5.0.

3.5 IMPORTANT POINTS

WELL PLUGGING

1. PLUG TYPES AND LOCATIONS

- Mechanical Plugs
  - Just above injection zone
  - Above unretrievable equipment
  - Bridge plugs
  - Sand or cement on top
- Cement Plugs
  - Above lowermost production or injection zone
  - Through each fresh water strata
  - Across casing stubs
  - At the surface

2. PLACEMENT AND SETTING OF CEMENT PLUGS

- Requires careful planning
- Contamination should be avoided
- Most effective if:
  - Static equilibrium established
  - Spacer fluid utilized
  - Surfaces of casing and borehole clean before placement
- Allow adequate time to set

3. TESTING CEMENT PLUGS

- No simple method
- Wait on cement (WOC) 8 to 24 hours
- "Tagging the plug"
- Testing recommended for:
  - Plugs critical to pressure control or USDW protection
  - Questionable plugs

4.0 SELECTION OF PLUGGING MATERIALS

Design of the plugging and abandonment operation entails selection of both materials and procedures, such as (1) the wellbore fluid system; (2) cement slurry type; (3) cement mixing, placement, and testing methods; and (4) precautions which should be taken to ensure the effectiveness of cement plugs. The proper selection and use of each of these components is essential to obtaining a satisfactory plugging job. This section will describe criteria for the selection of basic plugging materials, while Section 5.0 will provide a discussion of available cementing procedures.

The two basic materials used in the plugging and abandonment operation are: (1) the wellbore fluid (sometimes referred to as plugging fluid); and (2) the cement slurry used for the plug(s). Proper selection and use of each of these materials is essential in obtaining a satisfactory plugging job.

4.1 THE WELLBORE FLUID SYSTEM

The final phase of well preparation consists of the establishment of static well conditions. This is generally accomplished by circulation of a uniform fluid system throughout the wellbore. Of primary importance is the selection and establishment of this fluid system, which will not only provide the necessary environment for successful cement plug placement and setting, but will also serve as a stabilizing material between cement plugs.

The wellbore fluid system used in the plugging operation should be one which exhibits the following characteristics: (1) sufficient hydrostatic head or weight to prevent any fluid flow into the borehole; (2) ability of the fluid to remain in place over an indefinite period of time; and (3) chemical and physical stability of the material for an unlimited period of time (Gillespie, et al, 1973). Sufficient hydrostatic head is required to establish and maintain pressure control and prevent fluid movement during plug placement and setting processes. The ability of the fluid to remain stable and in place over an indefinite period of time is essential to both the success of the plug setting process and post-abandonment integrity of the wellbore.

As part of the abandonment planning process, it is important to realize that, in many cases, existing drilling fluids, wellbore fluids, and/or workover fluids are not necessarily designed to meet the above requirements. Therefore, a more suitable fluid system may need to be emplaced in the well prior to cement plug placement. The use of a fresh fluid system will enable the operator to select the necessary constituents of the fluid, enhancing its effectiveness in the plugging operation.

In cases where open-hole sections of the well are exposed during the plugging process, old drilling mud may be encountered. Many chemicals used in drilling muds are organic, and as such, can be very detrimental to the setting properties of a cement slurry. Muds that are most adverse to cement are those that have filtration controls and those that have thinners. Unless compensation is made for these mud types, the resultant retardation of the setting properties of the cement could cause a faulty plug.

Wellbore fluids and workover fluids found within the typical injection well may also contain constituents that would threaten the effectiveness of the cement slurry.

A recommended fluid for plugging and abandonment purposes would include the following materials:

(1) Water, fresh or brine.

(2) Bentonite (gel or clay).

(3) Attapulgite (a type of clay which acts as an extender).

(4) Lost circulation material (as needed).

Open-hole, plug-back studies show that the preferred fluid system has a Marsh funnel viscosity of 45 to 80 seconds, a plastic viscosity of 12 to 20 cp, a yield point of less than 5 lbs/100 square feet, and a water loss of less than 15cc (Herndon, et al, 1976).

Detailed hole preparation will depend largely on the plugging job design. In almost all cases, however, a gelled water as described above should prove to be an adequate plugging fluid. As mentioned earlier, the important thing is that the well be filled with a fluid of uniform weight (particularly important when using the balance method of plug placement). Once the borehole has been flushed and filled with a suitable fluid system, the operator can observe the fluid level and by doing so, note any fluid movement that may be occurring.

In fully cased wells where pressure control does not appear to be a problem, a specially prepared plugging fluid may not be considered a necessity. In these cases, pressure control may be provided by a simple water or brine solution. In fully cased wells where injection zone pressure is excessive, a weighted plugging fluid may be used for pressure control or the injection zone can be plugged back through the use of a mechanical plug. If a mechanical bridge plug is selected to seal off injection zone pressures, then a simple, low density fluid would be sufficient to maintain the static equilibrium of the well.

Establishing an effective plugging environment requires the emplacement of a fluid system which is able to meet the needs of the specific situation. This generally requires that existing wellbore fluids be replaced with the fresh fluid system. This fluid is mixed and circulated into the well using a string of tubing or drill pipe. At least one full circulation is required; several complete circulations are usually recommended to ensure uniformity of the new fluid system. After circulation has been completed, the well is allowed to stabilize and is observed to evaluate whether or not static well conditions exist. If the fluid level in the well changes, then static equilibrium has not been obtained and the plugging fluid should be altered and recirculated. After a static well condition has been achieved, cement plug placement activities can be initiated.

4.2 SELECTION OF A CEMENT SLURRY

The cement slurry used to plug and abandon a wellbore must be designed so that: (1) it provides sealing to prevent fluid movement between intervals; (2) it possesses good bonding characteristics to the pipe or formation; (3) it demonstrates durability; and (4) a long life may be expected. These conditions can generally be met using a densified cement such as API Classes A, C, G, and H, with a dispersant. These classes of cements are most acceptable due to the following reasons (Herndon, et al, 1976):

(1) They are less subjected to mud contamination and resultant loss of strength;

(2) They set and gain strength more rapidly, thus reducing time spent waiting for cement to set;

(3) With dispersant added, such slurries control water loss and minimize dehydration of the cement slurry which can result in premature cement setting or fluid movement in the borehole; and

(4) They can yield improved bonding characteristics and minimize damage to shales or bentonite sands by the addition of salt.

Class H cement is used predominantly in Gulf Coast and Midcontinent operations, while Class G cement is used among the West Coast and Rocky Mountain areas.

Regarding appropriate cement types for plugging, the following recommendations are made (Herndon, et al, 1976):

(1) For geographical areas which do not contain corrosive waters, a moderate sulfate resistant cement (API Class G or H) would be recommended.

(2) In geographical areas where high sulfate or acid waters are present, a special high sulfate resistant (SR) Class C cement could be used, or 50% pozzolan could be added to either Class C or H cements to provide high resistance to leaching.

(3) A dispersant should be used to lower the water content requirement in order to provide better strength and durability.

The selection of a cement composition is a function of well depth, temperature, and mud properties. Any special conditions in the well (e.g. lost circulation zones that will drain wellbore fluids or high temperatures that will flash set cement) must be considered when designing the cement slurry. Tables 4-1 and 4-2 provide a summary and description of some of the most commonly used oilfield cement types and additives that can counteract special conditions such as lost circulation and high temperatures.

TABLE 4-1
COMMON OILFIELD CEMENT TYPES[1]

TYPICAL CEMENTS:

API Classification	ASTM Type	Well Depth (ft.)	Static Temperature (°F)	Mixing Water (gal./sk.)	Slurry Weight (lb./gal.)	Slurry Yield (ft.³/sk.)	Comments
A (Common Portland)	I	0 - 6,000	80 - 170	5.2	15.6	1.18	Frequently used when special properties are not required; More economical than premium cements.
B (Common Portland)	II	0 - 6,000	80 - 170	5.2	15.6	1.18	Used when well conditions require moderate to high sulfate resistance; More economical than premium cements.
C (High Early)	III	0 - 6,000	80 - 170	6.3	14.8	1.32	Used when a higher early compressive strength is needed; More expensive than Portland and unless its special properties are required, should not be used. Generally, Portland with accelerators will give better early strengths.
G (Basic)	—	0 - 8,000	80 - 200	5.0	15.8	1.15	Can be accelerated or retarded for use over a wide range of depths and temperatures; Chemically similar to Class B, but a more uniform product; Used in W. Coast and N. Rocky Mountain areas.
H (Basic)	—	0 - 8,000	80 - 200	4.3	16.4	1.06	Can be accelerated or retarded for use over a wide range of depths and temperatures; Chemically similar to Class B, but a more uniform product; Use predominantly along Gulf Coast and in the Mid-continent areas.

SPECIALTY CEMENTS:

Name	Well Depth (ft.)	Static Temperature (°F)	Mixing Water (gal./sk.)	Slurry Weight (lb./gal.)	Slurry Yield (ft.³/sk.)	Comments
Pozzolanic - Portland (i.e. 50/50)	—	—	5.75	14.15	1.26	Less expensive than others and performs well with most additives; Basically a mix of Portland cement and Pozzolan; 50/50 Poz. means 50 % Portland and 50% Pozzolan; Has an almost universal application in well cementing; Lower in strength.
Pozzolan - lime	—	>140	4.65	14.00	1.18	Contains no Portland cement; Not normally used at temperatures less than 140°F.

1 - Information obtained from "Cementing" by Dwight K. Smith, Monograph Volume 4 of the SPE Henry L. Doherty Series and "Halliburton Cementing Tables", Halliburton Services.

Some important design properties to consider when selecting a cement slurry include: (1) compressive strength; (2) density; and (3) setting time. Cement compressive strength is a measure of the degree of resistance the cement plug has to any forces acting along one of its axes. Compressive strength is achieved after waiting for the cement to set; it will increase with time. A compressive strength of 500 psi is generally accepted by industry and regulatory bodies as adequate for most cement plugs.

The density of a cement slurry should always be great enough to maintain well control (i.e. control formation pressures); uniformity in slurry density should be maintained for plug placement purposes. Cement setting time is also an important property, particularly when setting multiple plugs. In such a case, the operator must be aware of the amount of time required for each plug to develop the desired compressive strength.

A variety of cement additives are available and may be required to compensate for special conditions in the well. Both high temperature and pressure act to accelerate the setting of cement. If these conditions exist in the well, a retarder should be added to the slurry to prevent premature setting. Fluid loss or lost circulation is another well condition that may be encountered. In these cases, filtration and lost-circulation control additives can be added to the cement slurry. Table 4-2 describes common cementing additives, their uses and benefits, and the cements to which they can be added. Table 4-3 illustrates the effects which additives have on the physical properties of cement.

TABLE 4-2
SUMMARY OF OILWELL CEMENTING ADDITIVES (Smith, 1987)

Type of Additive	Use	Chemical Composition	Benefit	Type of Cement
Accelerators	Reducing WOC time Setting surface pipe Setting cement plugs Combating lost circulation	Calcium chloride Sodium chloride Gypsum Sodium silicate Dispersants Seawater	Accelerated setting High early strength	All API classes Pozzolans Diacel systems
Retarders	Increasing thickening time for placement Reducing slurry viscosity	Lignosulfonates Organic acids CMHEC Modified lignosulfonates	Increased pumping time Better flow properties	API Classes D, E, G, and H Pozzolans Diacel systems
Weight-reducing additives	Reducing weight Combating lost circulation	Bentonite/attapulgite Gilsonite Diatomaceous earth Perlite Pozzolans Microspheres (glass spheres) Nitrogen (foam cement)	Lighter weight Economy Better fill-up Lower density	All API classes Pozzolans Diacel systems
Heavyweight additives	Combating high pressure Increasing slurry weight	Hematite Ilmenite Barite Sand Dispersants	Higher density	API Classes D, E, G, and H
Additives for controlling lost circulation	Bridging Increasing fill-up Combating lost circulation Fast-setting systems	Gilsonite Walnut hulls Cellophane flakes Gypsum cement Bentonite/diesel oil Nylon fibers Thixotropic additives	Bridged fractures Lighter fluid columns Squeezed fractured zones Treating lost circulation	All API classes Pozzolans Diacel systems
Filtration-control additives	Squeeze cementing Setting long liners Cementing in water-sensitive formations	Polymers Dispersants CMHEC Latex	Reduced dehydration Lower volume of cement Better fill-up	All API classes Pozzolans Diacel systems
Dispersants	Reducing hydraulic horsepower Densifying cement slurries for plugging Improving flow properties	Organic acids Polymers Sodium chloride Lignosulfonates	Thinner slurries Decreased fluid loss Better mud removal Better placement	All API classes Pozzolans Diacel systems
Special cements or additives				
Salt	Primary cementing	Sodium chloride	Better bonding to salt, shales, sands	All API classes
Silica flour	High-temperature cementing	Silicon dioxide	Stabilized strength Lower permeability	All API classes
Mud Kil	Neutralizing mud-treating chemicals	Paraformaldehyde	Better bonding Greater strength	API Classes A, B, C, G, and H
Radioactive tracers	Tracing flow patterns Locating leaks	Sc 46	—	All API classes
Pozzolan lime	High-temperature cementing	Silica-lime reactions	Lighter weight Economy	—
Silica lime	High-temperature cementing	Silica-lime reactions	Lighter weight	—
Gypsum cement	Dealing with special conditions	Calcium sulfate Hemihydrate	Higher strength Faster setting	—
Hydromite	Dealing with special conditions	Gypsum with resin	Higher strength Faster setting	—
Latex cement	Dealing with special conditions	Liquid or powdered latex	Better bonding Controlled filtration	API Classes A, B, G, and H
Thixotropic additives	Covering lost circulation zones Preventing gas migration	Organic additives Inorganic additives	Fast setting and/or gelation Less fall back Reduces lost circulation	All API classes
Mud spacers	Minimizing contamination	Variable	Uniform cement distribution	All cementing systems
Mud flushes	Aiding in drilling mud displacement Separating incompatible fluids	Variable	Better mud removal Reduced lost circulation	—

TABLE 4-3
EFFECTS OF ADDITIVES ON THE PHYSICAL PROPERTIES OF CEMENT (Smith, 1987)

		Accelerator (Calcium Chloride)	Bentonite	Pozzolan (Fly Ash)	Heavyweight Hematite	Retarders	Friction Reducers (Dispersants)	Filtration Additives	Lost Circulation Additives	Sand	Salt (10-20%)	Silica Flour	Sea Water
Water Requirements	Increases		(X)	X				X	X			X	
	Decreases						X						
Density	Increases				(X)					X	X		X
	Decreases		(X)	(X)			(X)		(X)			X	
Viscosity	Increases		X	X	X			X				X	
	Decreases	X				X	(X)			X	X		
Thickening Time	Accelerates	(X)											X
	Retards		X			(X)	X	X					
Fluid Loss of Slurry	Increases												
	Decreases		X				X	(X)					
Early Strength	Increases	(X)					X				X	X	X
	Decreases		X	X	X	(X)		X		X			
Final Strength	Increases			X			X					(X)	
	Decreases		X										
Durability	Increases			(X)			X					(X)	
	Decreases		X										
Types of Cementing job applications-- Where mostly used	Conductor Casing	X					X		X		X		X
	Surface Casing	X		X			X		X		X		X
	Intermediate Casing		X	X			X		X		X		X
	Production Casing		X	X	X	X	X	X	X			X	
	Liners				X	X	X	X				X	
	Squeezing					X	X	X					
	Plugging						X			X			

• For temperature 230°F
X Minor Effects
(X) Major Effects

4.3 IMPORTANT POINTS

SELECTION OF PLUGGING MATERIALS

1. **WELLBORE FLUID SYSTEM PURPOSE**

   - Clean hole
   - Static well condition
   - Uniform throughout wellbore
   - Necessary environment for successful cement plug setting and placement
   - Stabilizing material between plugs

2. **WELLBORE FLUID SYSTEM PROPERTIES**

   - Sufficient weight/density
   - Ability to remain in place over long period of time
   - Chemical and physical stability for unlimited time
   - Recommended fluid would contain:

     - Water
     - Clay
     - Gel
     - Lost circulation material

3. **CONSIDERATIONS IN SELECTING PROPER CEMENT SLURRY**

   - Compressive strength
   - Weight/density
   - Additives
   - Recommended properties:

     - Sealing to prevent fluid movement
     - Good bonding characteristics
     - Durability
     - Long life

5.0 SELECTION OF CEMENTING PROCEDURES

Inherent to plugging job design is the selection of cementing procedures which will adequately fulfill abandonment requirements. The following provides a summary of: (1) cement mixing techniques; (2) cement plug placement methods; and (3) cement testing methods.

5.1 CEMENT MIXING TECHNIQUES

Cement should be mixed according to American Petroleum Institute (API) water/cement ratio requirements. Too much water will delay the setting of the cement and will produce a weaker cement with lower resistance to corrosion. Mixing water should be obtained from the purest available source. Ideally, the water supply for mixing cement should be clean and free of contaminants such as soluble chemicals, organic matter, etc. Potable water is always recommended. Clear water is usually suitable. Saline waters should be used with caution since they can act as an accelerator and cause premature setting. This effect can be offset by chemical retarders. It is always wise to pretest the cement slurry mixture (using water to be used in actual operation) in the laboratory to ensure that it exhibits the desired setting properties.

The cement mixing system should be capable of accurately proportioning and blending the dry cementing materials with the mix water, thus, producing a cement slurry with predictable properties. The system should include an accurate means of monitoring to ensure that the correct water/cement ratio is maintained, and a high quality cement slurry is pumped. Slurry density should be monitored with a standard mud balance, densimeter, or fluid density balance.

Three methods predominantly used to mix cement slurry for "oilfield" cementing are: (1) jet mixing; (2) recirculating mixing; and (3) batch mixing.

Jet mixing is accomplished with equipment consisting of a hopper, mixing bowl, water line, and mixing tub. Dry cement is fed into the hopper, which funnels into the mixing bowl where it meets jetted water. Jetted water acts as the mixing mechanism. The prepared slurry is then transferred to the mixing tub and is ready for use.

Recirculating mixing is similar to jet mixing. Mixed cement is recirculated from an agitated vessel and jetted where dry bulk cement is pipe-fed into the system. This process results in a more uniform slurry.

Batch mixing differs from jet and recirculating mixing in that most mixing is accomplished with a large vessel. The recirculating technique is used, however, to introduce dry bulk cement to the system. In essence, a "batch" of cement is mixed.

Although not considered a common practice, some areas still use "hand-mixing" methods for P&A cementing operations. This basically involves pouring dry cement into a tub or barrel, adding water, and stirring with a wooden stick. This practice is not recommended for several reasons: (1) Inaccuracies in water/cement ratio requirements and slurry density are more likely to occur; (2) Such a mixing system provides no accurate method for monitoring the slurry density as the job progresses; (3) Only small batches of cement can be mixed (e.g. one sack at a time), which further contributes to nonuniform characteristics of the cement slurry. All of these factors are likely to produce a cement slurry with unpredictable properties, one which may not meet design requirements, and therefore may not set up properly.

5.2 CEMENT PLUG PLACEMENT METHODS

Several methods are available for the placement of cement plugs during well plugging operations. The most commonly used plug-placement techniques are the: (1) balance method; (2) cement retainer method; (3) two-plug method; and (4) dump-bailer method. Cement should not be dumped from the surface as it will be severely contaminated by the wellbore fluid (as the cement migrates downward) and will not set up properly. Each of the accepted methods has advantages as well as limitations. The selection of the most ideal plug placement method is a function of various factors, such as well construction, plug location, well condition, cost, etc. Each of the standard plugging techniques is summarized briefly below:

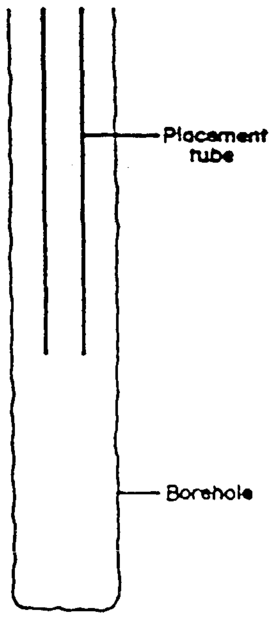
5.2.1 Balance Method

The balance method consists of running tubing or drill pipe into casing or open hole and displacing the cement. The cement slurry is pumped down the tubing or drill pipe and back up around the annulus to a calculated height which would hydrostatically balance the cement inside and outside the pipe. The tubing is then pulled slowly out of the top of the cement, leaving a solid cement plug in the hole. When the pipe is a considerable distance above the top of the cement plug, the pipe is then cleaned by reverse circulation. In order to achieve success using the balance method, the wellbore fluid system <u>**must**</u> be in a state of static equilibrium. Any fluid movement can hinder the quality of the cement plug placed by this method. The balance method is by far the most commonly used technique for emplacing cement plugs. However, the method is not necessarily simple to implement. Figure 5-1 illustrates the basic steps involved when utilizing the balance method.

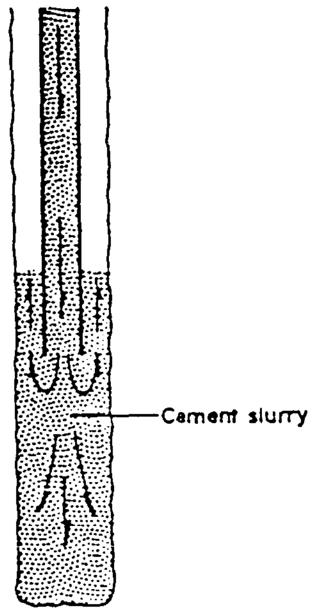
The success of the balance method requires considerable operator skill in removing the placement tubing without causing significant contamination of the cement slurry. To minimize the possibility of disturbing the slurry while removing the placement string, a small diameter tubing is required. The small diameter tubing increases the size of the annulus between the placement string and casing or borehole wall which allows the withdrawal of the tubing without causing an excessive drop or surge in the cement level that can be brought on by the swabbing action of pulling the tubing (Geraghty and Miller, Inc., 1982).

Balancing cement levels requires careful planning. Caution must be exercised in calculating gel, spacer, and cement volumes to be sure that an effective cement plug will result. In uncased holes, careful measurements of the borehole diameter often

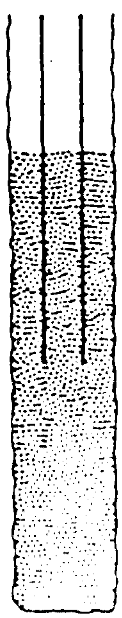
PLUG PLACEMENT
PRINCIPLES OF THE BALANCE METHOD
(Geraghty and Miller, Inc., 1982)



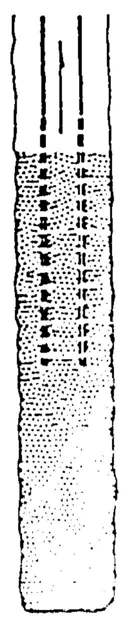
Placement tubing run into hole



Cement-slurry placed in hole



Level of cement-slurry balanced



Placement tubing removed

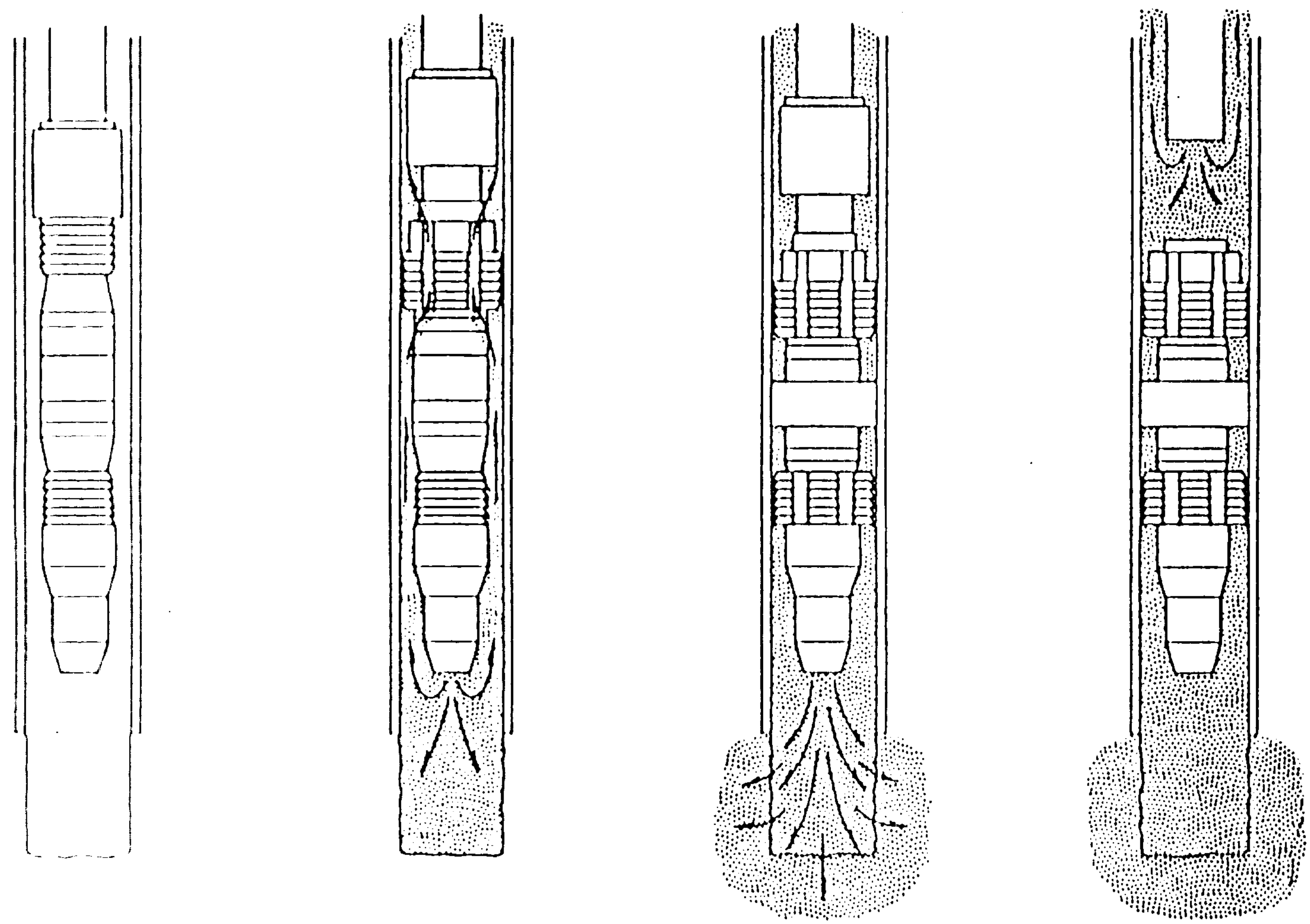
FIGURE 5-1

becomes critical in making the necessary calculations. A slight overbalance of cement in the tubing is commonly practiced to compensate for the difficulties involved in precisely matching cement level prior to withdrawal of the placement tubing and in minimizing contamination of the cement during tubing withdrawal (Geraghty and Miller, Inc., 1982). Section 5.5 provides sample calculations for implementation of the balance method.

5.2.2 Cement Retainer Method

The cement retainer method, a specialized form of the balance method, is used in cased portions of the hole and utilizes a retainer tool. The retainer tool is attached to the placement tubing and lowered to the bottom of the well. The cement slurry is then pumped through open valves of the tool and back up into the hole until the cement height rises to 50 to 100 feet above the ultimate setting depth of the tool. The retainer is then retracted to the desired depth and set. After the retainer is set, the cement is forced by pressure into the surrounding formation(s). Upon pumping the desired amount of cement below the retainer, the tubing is then picked up and disengaged from the tool, which causes tool valves to close. Any residual cement in the tubing will then fall out on top of the retainer tool, forming an additional cement plug. Once the tubing has been raised above the cement top, it is cleaned by reverse circulation. Figure 5-2 depicts the cement placement process using the cement-retainer method.

PLUG PLACEMENT
PRINCIPLES OF THE CEMENT RETAINER METHOD
(Geraghty and Miller, Inc., 1982)



Retainer run into hole

Cement-slurry placed

Packer set and cement squeezed into formation

Placement tubing removed

FIGURE 5-2

Although more expensive than the conventional balance method, the cement retainer method offers several advantages which make its application to setting the bottom plug in injection wells favorable. Some of the method's potential advantages are listed below (Geraghty & Miller, Inc., 1982):

(1) By forcing cement out under pressure into the surrounding formation, this technique ensures adequate bonding between the plug and the formation.

(2) When the plug is to be placed at the bottom of the casing, the cement retainer method creates a more reliable barrier not only to flow inside the casing, but also to flow in the annular space between the casing and formation.

(3) In some cases, the cement retainer method may offer an effective alternative to squeeze cementing the lower portion of a casing string when the integrity of a primary cement job is suspect.

(4) Once the valve is closed, the cement retainer serves as a barrier to flow past the plug and thereby increases the reliability of the plug.

(5) In addition, immediately after the plug is set, it can be pressure tested. The reliability of the plug thus proved, the need to reenter the hole after the plug sets for testing is eliminated.

(6) The method provides excellent control of the cement slurry, and by providing a barrier to gas percolating up through the well, the retainer helps to prevent any potential contamination of the cement while it is setting.

5.2.3 Two-Plug Method

The two-plug method utilizes top and bottom cementing plugs to isolate the cement from both the wellbore and displacement fluids in an effort to avoid contamination of the cement slurry.

The two-plug method involves a top plug, bottom plug, and a latch-down type plug catcher. The procedure, depicted in Figure 5-3, begins by running the placement tubing with the attached plug catcher into the hole to the depth desired for the bottom of the cement plug. The bottom plug, followed by the appropriate volume of cement slurry, is then pumped into the pipe. The top plug is pumped behind the cement slurry and is followed by a plugging fluid. When the bottom plug reaches the plug catcher, it passes through the catcher and flows out into the well. The cement slurry is then displaced into the well; when the top plug reaches the plug catcher, it is unable to pass through the catcher preventing any further displacement of fluid. The placement tubing can then be slowly raised out of the cement leaving a solid plug behind. The plug catcher is designed so that the pressure can be reversed, enabling fluid to flow back into the placement tubing. If needed, the tubing can then be raised and reverse circulated to establish the top of the cement plug.

PLUG PLACEMENT
PRINCIPLES OF THE TWO-PLUG METHOD
(Geraghty and Miller, Inc., 1982)

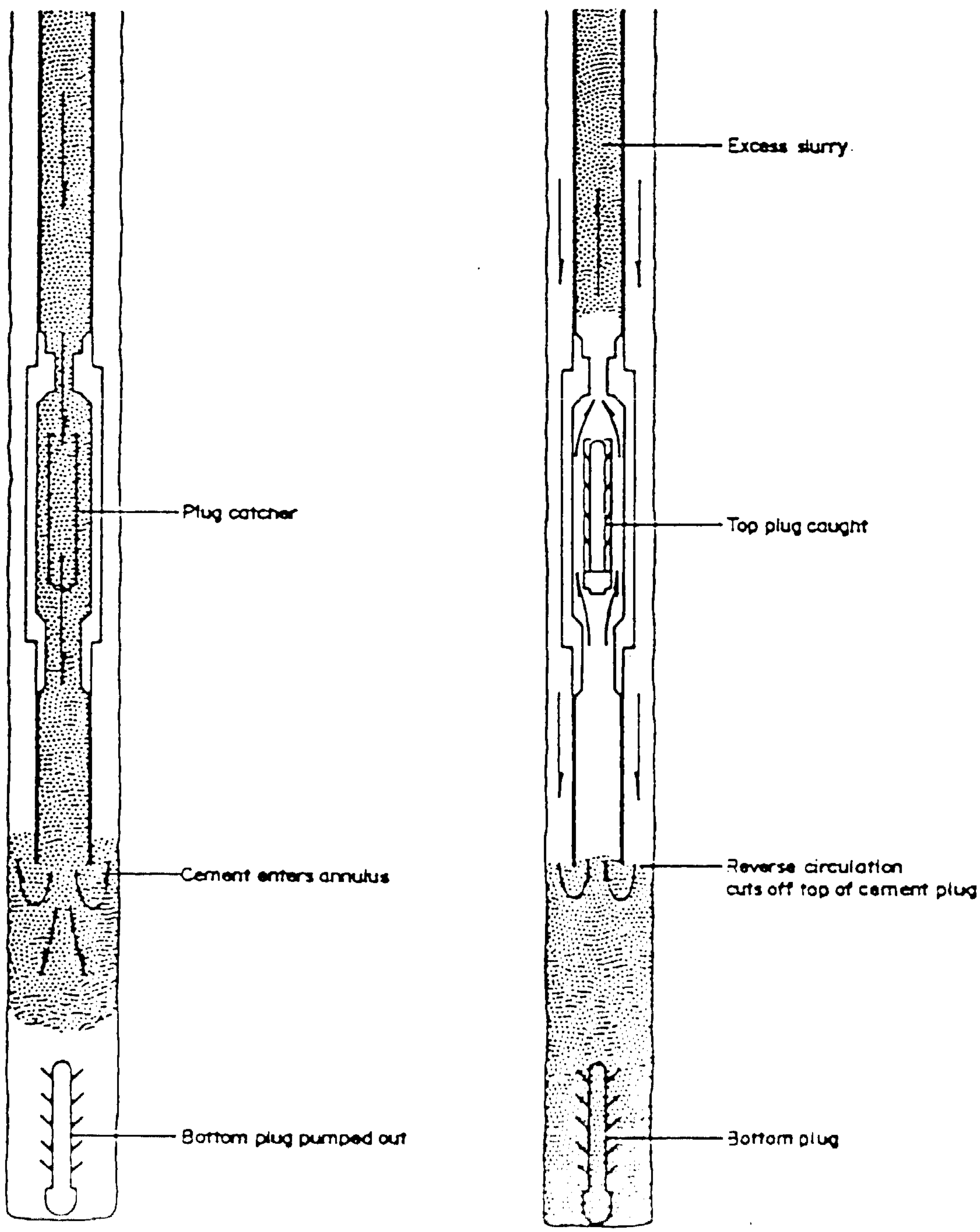


FIGURE 5-3

Although more costly, this technique offers several advantages over the balance method (Geraghty and Miller, Inc., 1982):

(1) The plugs act to separate the plugging fluid and cement slurry, reducing the potential for cement contamination.

(2) The bottom plug helps wipe plugging fluid from the inner walls of the placement tubing as it is pushed down into the well in front of the cement slurry, further reducing cement slurry contamination.

(3) Most importantly, the two-plug method offers excellent control of the cement and eliminates overdisplacement of cement into the well.

5.2.4 Dump-Bailer Method

The dump-bailer method, although available as a plug-setting mechanism, is seldom used for plugging and abandonment operations due to a number of limitations. When using this method, a mechanical bridge plug is normally placed below the location at which cement is to be placed. The bailer, a cylindrical container which holds a fixed amount of cement, is lowered on a wireline and dumps the cement on top of the mechanical plug. This method of plug placement (illustrated in Figure 5-4) is limited by the amount of cement that can be placed with each run. In addition, each load of cement must be set up prior to

PLUG PLACEMENT
PRINCIPLES OF THE DUMP-BAILER METHOD
(Geraghty and Miller, Inc., 1982)

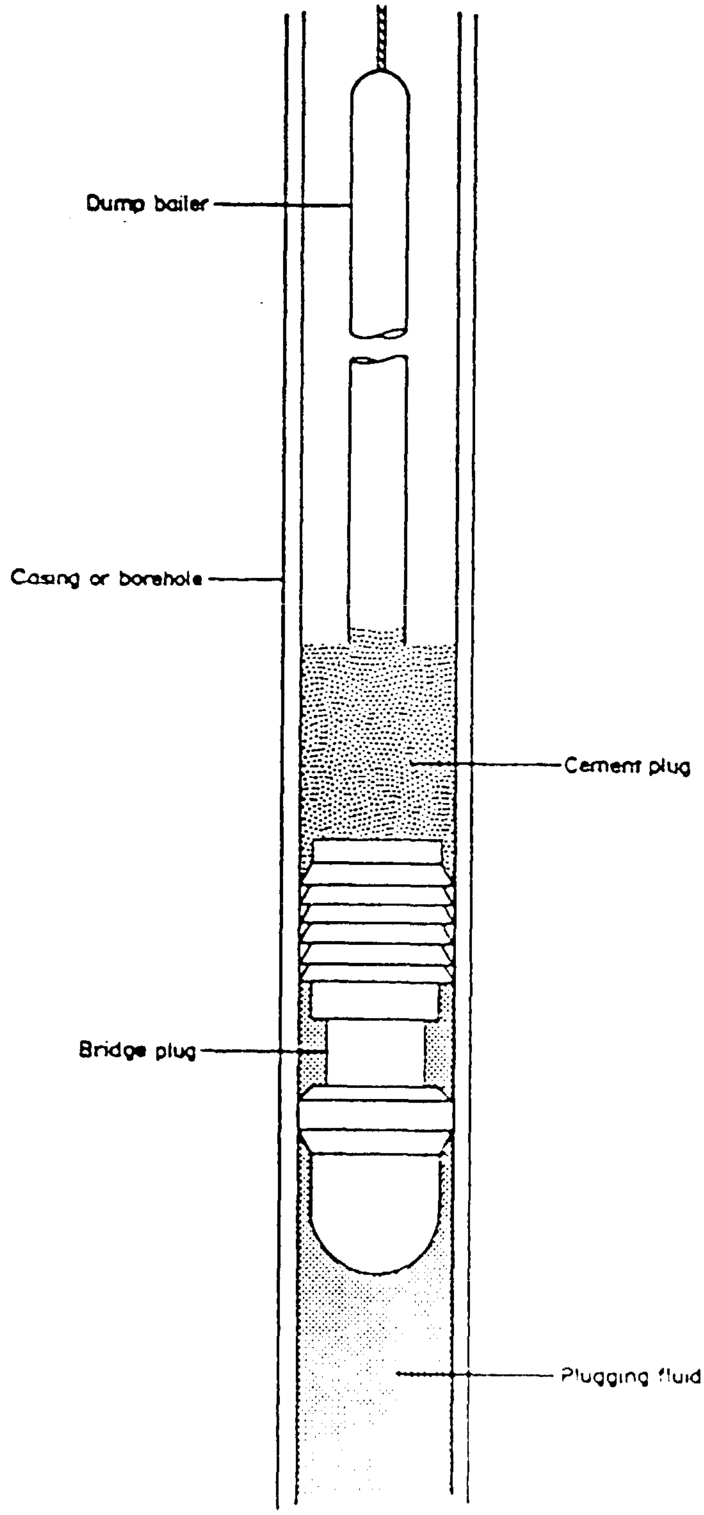


FIGURE 5-4

emplacement of an additional load. Since the dump-bailer method can be time-consuming and inconvenient, it is generally not selected as the primary plugging technique.

Table 5-1 (Geraghty & Miller, Inc., 1982) provides a summary of each of the four plugging methods with a description of the potential applications of each.

5.2.5 Placement of Multiple Plugs

The majority of abandonment programs require that a series of plugs be placed in the well to be plugged. In executing the operation, certain steps need to be taken during plug placement. In most cases, each cement plug should set up before placement of the next cement plug in the well. This is necessary to allow the cement slurry to solidify in the presence of a static environment. Displacement of cement slurry into the well for setting a second plug will likely disturb the fluid below, increasing the potential for contamination. In addition, it is often necessary to tag the cement plug, thus verifying its position and solidification. This generally requires waiting for 8 to 24 hours for cement to set up properly. After tagging the cement plug, it may be necessary to recirculate the plugging fluid to ensure that fluid weight is equalized throughout the unplugged portion of the wellbore. The plugging fluid is then brought back to a static state before setting the next plug.

TABLE 5-1

POTENTIAL APPLICATIONS OF PLUGGING METHODS (Geraghty and Miller, Inc., 1982)

Application or Use	Balance Method	Retainer Method	Two-Plug Method	Dump-Bailer Method
Cased wells	3	3	3	3
Uncased wells	3	1	3	3
Large diameter wells	3	3	3	1
Small diameter wells	3	3	3	3
Deep wells	2	3	3	1
Shallow wells	3	2	2	3
Reduced need of establishing static equilibrium	1	2	1	1
Reduced need of thorough well cleaning	1	2	1	1
Reduced need of thorough well inspection	1	2	1	1
Placement of bottom-hole plugs	3	1	3	3
Placement of intermediate depth plugs	2	3	2	1
Ability to squeeze cement slurry	1	3	1	1
Potential for adequate cement bonding to formation and casing	2	3	2	2
Prevention of cement slurry contamination	2	2	3	1
Prevention of cement movement of migration	2	3	2	2
Accuracy of depth of placement of cement	2	2	2	3
Ease of calculating adequate cement volume	2	3	3	2
Ease of installing adequate cement volume	3	3	3	1
Effectiveness in minimizing time and expense of plug testing	1	3	1	1

Note: 3 - good
2 - fair
1 - poor

Setting multiple plugs generally requires repetition of the above sequence of steps for each plug. However, when plugs are set using the retainer method, the operator can raise the placement tubing to set the next plug immediately after setting the lower plug. This is possible because the retainer assures the position of the plug and isolates the cement below it from any influences in the borehole above the plug.

5.2.6 Tools and Materials to Assist in Effective Plug Placement

Regardless of which of the basic plugging techniques is used, the major concern in any plugging operation is to place the cement plug(s) without contaminating the cement. As mentioned earlier, it is essential that prior to the placement of plugs, the wellbore be conditioned through adequate circulation of an appropriate fluid and that the hole be in a static condition with the fluid weight equalized top to bottom. In addition to proper well preparation, there are a number of procedures which can be used to reduce the risks of achieving an ineffective cement plug.

Preparation of Borehole Walls

The use of scratchers and centralizers placed on the lower joints of the placement tubing maximizes displacement efficiency and prepares borehole walls for cement bonding. Scratchers, which are used to remove mudcake from borehole walls, consist of two types; the first type removes mudcake with a rotating motion, while the other type uses a reciprocating (up and down) motion. These devices are lowered into the well when the tubing is lowered to emplace the cement slurry. When scratchers are positioned opposite the zones in which the plug is to be set, the pipe is rotated or reciprocated to remove mudcake.

Centralizers also may be attached to the bottom of the placement tubing to position it in the center of the hole. This practice is useful in preventing cement from channeling to one side of the annulus in order to permit displacement of the plugging fluid.

In addition to wall scratchers and centralizers, chemical washes may also assist in borehole preparation. These washes, which are pumped ahead of the cement slurry, assist in the removal of mudcake and other deposits from borehole walls. Chemical washes are of two basic types, thinners and acids. Thinners are most effective in water-based plugging fluid systems and act to disperse any flocculated clay particles. Acid washes act to shrink mud particles, thereby dispersing mudcake. Prewashes must be used with caution since they do contain chemicals which can retard or inhibit cement setting.

Contamination Prevention

Cement slurry contamination can often be prevented through the use of spacer fluids. These fluids can be placed ahead of and/or behind the cement slurry as it is placed in the tubing string. Spacers serve to separate the plugging fluid and cement slurry, and are frequently used in conjunction with cementing plugs (e.g. two-plug method). Spacer fluids may be similar to the chemical washes discussed above, or they may be specially designed by service companies.

In addition to prewashes and spacer fluids, small amounts of non-chemically treated drilling muds may also be pumped ahead of the cement slurry. Such muds are used to prevent adverse reactions which might occur when the plugging fluid comes in contact with chemical washes or the cement slurry. These muds generally consist of bentonite, water, and any necessary weighting material.

5.3 TESTING CEMENT PLUGS

There is no simple method for accurately testing a cement plug in open hole. The most common way is to simply tag the plug after waiting on the cement to set up and build compressive strength (8 to 24 hours). This is performed by running pipe (tubing or drill pipe) back into the hole to locate the plug by applied weight. Although tagging a plug may give an indication of whether some degree of plugging has occurred at the desired location, it says little about the quality of the plug. A cement plug may be hard on top, but soft farther on down. If the plug is found to be where it is supposed to be, it can still be soft so that in time, fluids can pass through it.

Due to time spent waiting on cement to set, it is not always feasible or practical to tag all cement plugs. For example, if only daylight hours are worked and the cement set-up time is at least twelve hours, only one plug can be set each day. If proper plugging procedures are followed closely and care is taken in the plug placement process, an effective plug can generally be expected. Cement plugs placed on top of mechanical plugs need not be tested, as isolation is accomplished with the mechanical plug.

Plug testing is recommended for: (1) plugs that are critical to pressure control or USDW protection; (2) plugs which are suspected to exhibit inferior cement quality; and (3) plugs which are suspected to be contaminated through unsuccessful placement operations.

5.4 GUIDELINES TO ENSURE CEMENT PLUG QUALITY

The following recommendations should be helpful in placing a cement plug successfully (Herndon, et at, 1976; Smith, 1987):

(1) Circulate the hole sufficiently before performing the job. Use a mud (or gel) of low yield point, low plastic viscosity, and sufficient weight to control the well.

(2) Ensure that the wellbore is completely static (no fluid movement) before plugging operations begin.

(3) For maximum bonding, place the plug across a competent, hard formation. Caliper logs should be consulted in selecting plug locations.

(4) Precede the cement with sufficient flush or spacer, if necessary.

(5) Use a densified (low water ratio) cement (API Class A, C, G, or H) that will tolerate considerable mud contamination.

(6) To minimize contamination during cement placement, rotate tubing using centralizers and scratchers on tail pipe (lower part of work string) where the hole is not excessively washed out.

(7) Carefully calculate cement, water, and displacement volumes. Always plan to use an ample amount of cement.

(8) Place the plug with care and withdraw the pipe slowly out of the cement to minimize mud contamination.

5.5 SAMPLE PROCEDURES AND CALCULATIONS

5.5.1 Typical Plugging Operation

This section is intended to provide the reader with a practical example of a plugging procedure. Figure 5-5 depicts the sample well, a typical injection well, in its present and proposed condition. It is assumed that the following circumstances exist:

- All casing, tubing, and cement exhibit mechanical integrity.

- There are no flowing zones nor are there any lost circulation zones.

CONVENTIONAL WELL CONSTRUCTION
SAMPLE PLUGGING JOB DESIGN

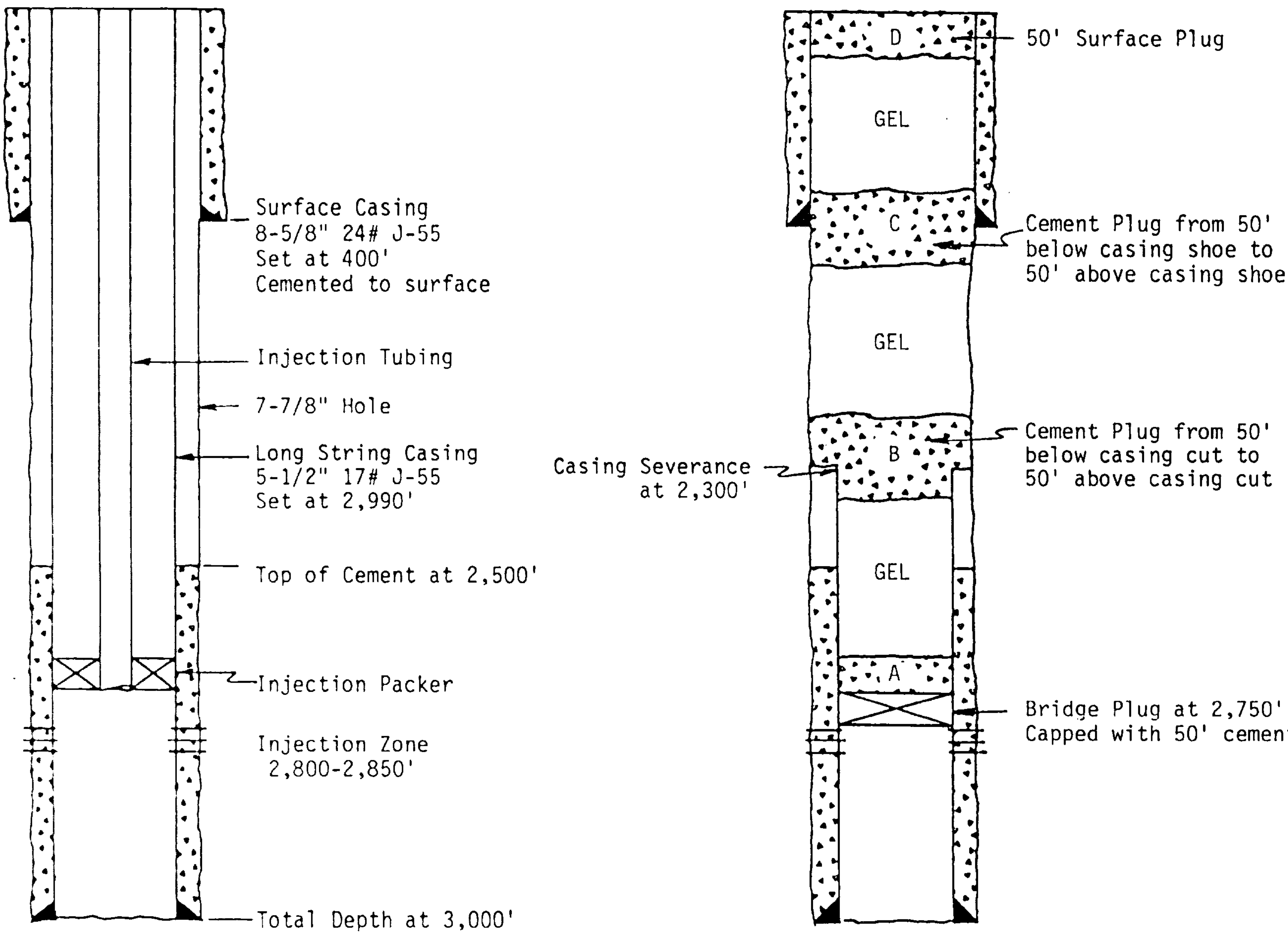


FIGURE 5-5

- Equipment removal is feasible.

- Workover equipment is readily available.

- Plugs will be placed by the balance method.

A typical plugging procedure for the sample well is presented below:

(1) Move in and rig up. Unseat packer and pull out of the hole with injection tubing and packer.

NOTE: Injection tubing will be used as the workstring.

(2) Rig up a wireline unit and run in the hole with a gauge ring for the 5-1/2" casing (to check for obstructions). Pull out of the hole.

(3) Run in the hole with a cast iron bridge plug. Set the bridge plug at 2,750'. Pull out of the hole.

(4) Run in the hole with a free point indicator tool. Find the free point of the 5-1/2" long string casing (assume at 2,350').

(5) Run in the hole with a jet cutter and shoot off 5-1/2" casing at 2,300'. Pull out of the hole with tool.

(6) Pull the 5-1/2" casing string out of the hole, laying it down as coming out of the well.

(7) Run in the hole with the tubing string to 2,750'. Pull up slightly and circulate the hole with an appropriate preflush to clean hole.

(8) Circulate one hole volume (150 bbls.) of gelled plugging fluid to establish static well conditions and prepare well for plugging. Observe fluid level to ensure that the hole is in a static condition.

(9) Assuming that the wellbore is in a static condition, emplace the bottom cement plug (± 6 sks.). Using the balance method, pump a spacer followed by the cement slurry, spacer, and displacement gel.

(10) Pull tubing slowly out of the cement by about 200'. Reverse circulate any excess cement out of the tubing using gel as the circulating fluid.

(11) Pull up to 2,350' and emplace a 100' cement plug (± 23 sks.) using the same technique. Utilize 20% excess volume for all cement slurries as a margin of safety.

(12) Pull up to 450' and emplace a 100' cement plug (± 32 sks.) across the surface casing shoe using the same placement technique. Pull out of the hole with the tubing.

(13) After waiting 12 hours for cement to set, run in the hole with the tubing and tag the surface casing plug.

(14) Assuming that the plug has been successfully tagged, pull up to 50' and emplace the 50' cement plug ($\pm$ 15 sks.) at ground surface.

(15) Mark and restore the well site according to State requirements. Rig down and move off the site.

Sample plugging fluid calculations for the job design depicted in Figure 5-5 are presented below:

Assume a 20% excess volume required for open hole portions of the well.

Plugging Fluid Calculation

This calculation assumes that the wellbore is circulated with one hole volume of mud or gel after pulling the long string casing.

(2,700'-2,300')(.0232 bbl./ft.)	=	9.3 bbls.	(5-1/2" csg.)
(2,300'-400')(.0602 bbl/ft.)(1.2)	=	114.4 bbls.	(7-7/8" O.H.)
(400'-0')(.0636 bbl./ft.)	=	25.4 bbls.	(8-5/8" csg.)
Approximate Mud Required	=	150 bbls.	

Cement Plug Calculations

These calculations assume a cement slurry yield of 1.18 ft.^{3}/sk.

Plug A.	(50')(.1305 ft.^{3}/ft.)	=	6.5 ft.^{3}
	6.5 ft.^{3}/1.18 ft.^{3}/sk.	=	6 sks. cement
Plug B.	(50')(.1305 ft.^{3}/ft.)	=	6.5 ft.^{3}
	(50')(.3382 ft.^{3}/ft.)(1.2)	=	20.3 ft.^{3}
	Total	=	26.8 ft.^{3}
	26.8 ft.^{3}/1.18 ft.^{3}/sk.	=	23 sks. cement
Plug C.	(50')(.3382 ft.^{3}/ft.)(1.2)	=	20.3 ft.^{3}
	(50')(.3575 ft.^{3}/ft.)	=	17.9 ft.^{3}
	Total	=	38.2 ft.^{3}
	38.2 ft.^{3}/1.18 ft.^{3}/sk.	=	32 sks. cement
Plug D.	(50')(.3575 ft.^{3}/ft.)	=	17.9 ft.^{3}
	17.9 ft.^{3}/1.18 ft.^{3}/sk.	=	15 sks. cement
	Approximate Cement Required	=	76 sks. cement

5.5.2 Other Sample Calculations

The remaining pages of this section present detailed sample calculations for cementing procedures associated with plugging and abandonment. These examples have been excerpted from reputable publications (See references).

PLUG BALANCING

When a cement plug is to be spotted through tubing or drill pipe, it is important to calculate the necessary volume of spacer to be pumped behind the cement slurry. The correct volume ensures that the column of fluid in the annulus (displaced mud, spacer, cement slurry) is adequately balanced by the column of fluid in the tubing (displacing mud, fluid behind the slurry, cement slurry). It is this process that is known as 'balancing a plug'.

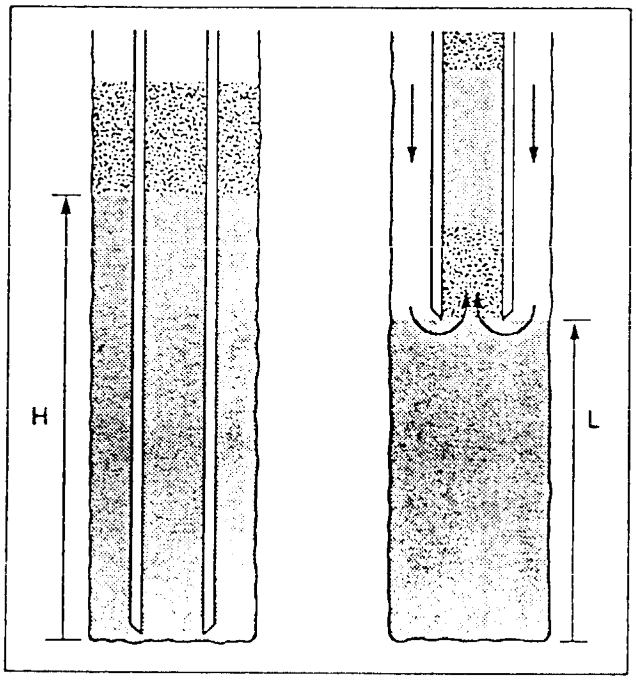


FIG. 8.5

Once a plug has been spotted, the tubing is pulled up until its end is positioned just above the desired top of the plug and reverse circulation is established. This operation cuts off the plug at the desired height.

The steps involved in plug balancing calculations are

1) To calculate the slurry volume and number of cement sacks required to fill the desired height L. Thus

$$\text{Volume} = L\,[\text{ft}] \times \text{[illegible]}\,[\text{cu ft/ft}] \times \text{excess factor}$$

$$\text{Sacks} = \frac{\text{volume [cu ft]}}{\text{slurry yield [cu ft/sk]}}$$

2) To balance the chemical wash or spacer pumped ahead of the cement slurry by pumping water behind the cement slurry. In such an instance, with fluid of the same density both before and after the slurry, we can use the formula

$$\text{water behind [bbl]} = \frac{\text{water ahead [bbl]} \times \text{tubing volume [cu ft/sk]}}{\text{annular volume [cu ft/ft]}}$$

3) To calculate the height of the balanced cement column prior to pulling up the tubing.

$$H(\text{ft}) = \frac{\text{slurry volume [cu ft]}}{\text{annular volume [cu ft/ft]} + \text{tubing volume [cu ft/ft]}}$$

4) To calculate the volume of displacement fluid

Displacement fluid volume [bbl]
= (tubing length - H) [ft] x tubing volume [bbl/ft]
– water behind from step 2 [bbl]

As a general rule, it is advisable to underdisplace the quantity of cement down the tubing by a small amount (¼ to ½ bbl per 1000 ft, depending upon the size of the tubular goods).

EXAMPLE CALCULATIONS

- A 200 ft plug is required in an 8¼ inch open hole.
- The bottom of the plug is to be set at 6000 ft.
- The cement is a neat Class G.
- To spot the plug, a 4½ inch, 16.6 lb/ft, drill pipe will be used and 6 bbl of water will be pumped ahead of the cement slurry.
- 20% excess cement is believed necessary to allow for hole enlargement.

1) Slurry volume required

0.3712 cu ft/ft x 200 ft x 1.2 = 89.1 cu ft

2) Sacks of cement

$$\frac{89.1 \text{ cu ft}}{1.15 \text{ cu ft/sk}} = 77 \text{ sk}$$

3) Mix water required

$$\frac{77 \text{ sk} \times 4.97 \text{ gal/sk}}{42 \text{ gal/bbl}} = 9.1 \text{ bbl}$$

4) Water behind

Vol of water behind =

$$\frac{\text{vol of water ahead} \times \text{drill pipe capacity}}{\text{annular capacity}}$$

$$= \frac{6 \text{ bbl} \times 0.[\text{illegible}] \text{ cu ft/ft}}{0.2[\text{illegible}] \text{ cu ft/ft}} = [\text{illegible}]$$

5) Height of plug before pulling the drill pipe

$$H = \frac{\text{slurry volume [cu ft]}}{\text{annular volume [cu ft/ft]} + \text{drill pipe volume [cu ft/ft]}}$$

$$= \frac{89.1 \text{ cu ft}}{0.[\text{illegible}] \text{ cu ft/ft} + 0.[\text{illegible}] \text{ cu ft/ft}} = [\text{illegible}] \text{ ft}$$

6) Displacement volume

[(6000 ft - 262 ft) 0.01422 bbl/ft] - [1.8 bbl] = 79.9 bbl

Note that the total slurry volume, including the excess allowed, has been used during the course of this calculation. We must conclude, therefore, that the plug will only be well balanced if the estimated excess was accurate. If this was not the case, the plug will be over or under displaced.

SQUEEZE CEMENTING

Squeeze cementing is covered more fully in Chapter 12. For this chapter, however, the following facts should be considered.

The high pressure technique involves breaking open the formation so as to pump and dehydrate a slurry into the resulting fractures.

The low pressure technique consists of placing cement over a desired interval, and then applying just sufficient pressure to dehydrate the cement into the perforation channels and surrounding voids.

Both techniques may be employed by using isolating tools such as packers and cement retainers. Alternatively, the Bradenhead squeeze method may be employed.

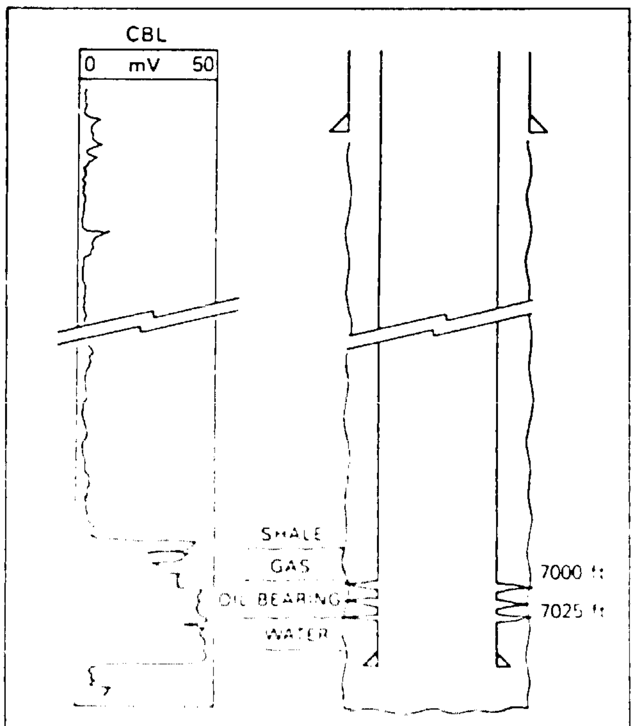


FIG. 8.6

In order to demonstrate such techniques more fully, let us consider an example using data relating to calculations often made in the field.

Consider the following:

An evaluation of a primary cementing job has shown poor isolation in front of the production zone with the result that production tests have yielded high gas and water cut oil. To work the well in an economically viable manner, it is necessary to eliminate the entry of water and gas into the wellbore by more effectively isolating the oil interval.

WELL DATA

Total depth = 7050 ft.
Casing = 5½ inch, 17 lb/ft, 0.1305 cu ft/ft
Tubing = 2 inch ID, 4 lb/ft, 0.02272 cu ft/ft
Open hole = 6⅝ inch drilled through pay
Formation fracturing gradient = 0.7 psi/ft
BHCT = 130 F

FLUID DATA

Cement slurry to be used

Class G + 0.2 gal/sk FLAC* + 0.1 gal/sk TIC*
Slurry weight = 15.8 lb/gal
Mix water = 4.97 gals/sack
Slurry yield = 1.15 cu ft/sack
Thickening time at 130 F BHCT = 120 min

Completion Fluid

NaCl brine 9.5 lb/gal

Working with this data we shall develop field calculations for the purposes of low pressure squeeze jobs. The Bradenhead technique shall be used in our first example and in the second, we shall consider the calculations for a squeeze through a packer.

BRADENHEAD SQUEEZING

SLURRY VOLUME

The object of this exercise is quite simply to fill any voids in the annular space with dehydrated cement. When attempting such an operation, however, one should be aware of the potential problems involved - it may be impossible to squeeze a cement slurry into the annulus without fracturing; the CBL might indicate poor cement casing/formation bonding but not necessarily poor cement filling.

For our purposes we shall take a critical case in which the cement in front of the pay zone has not set and together with the drilling mud has been removed from the annular space by the producing fluids.

An injection test, performed with clean fluids, demonstrated a fair injection rate at a low pressure. The perforations may be considered as clean, as they have been subjected to high negative differential pressures during the shooting and production tests. We shall assume that 80% of the perforations are open.

The volume of cement needed to satisfy the above conditions may be calculated as follows:

Annular space

Distance between CBL peaks = 65 ft

Volume of annular space between CBL peaks

= 0.0744 cuft/ft x 65 ft = 4.84 cuft

Hence, sacks of cement for annular space

= 4.84 sacks

Volume of cement left inside casing

Top of cement at 6980 ft

0.1305 cuft/ft x 45 ft = 5.87 cuft

Hence, sacks of cement = 5.10 sacks

i.e. total sacks = 9.94

Add 20% excess cement = 1.99

Therefore total cement in sacks = 11.93 sk

say 12 sk

As can be seen, even having taken into account the fact that 100% of the annular space has to be cemented, the requisite volume of dry cement remains relatively small.

For the purposes of this hypothetical job, therefore, the recommended approach would be to mix 20 sacks of cement and reverse out the excess above the 6980 ft level

SPOTTING THE CEMENT SLURRY IN FRONT OF THE PERFORATIONS

If one is to avoid squeezing damaging fluids ahead of the slurry the cement must be properly balanced in front of the perforations

The plug balance can be calculated according to the method shown earlier in this chapter The rest of the calculations proceed as follows

Water ahead of the cement slurry = 5 bbls

Water behind the cement slurry =

$$\frac{5\ \text{bbl x tubing unit volume}}{\text{annular unit volume}} = \frac{5 \times 0.02272}{0.0998} = 1.14\ \text{bbl}$$

Height of balanced cement column

$$\frac{20\ \text{sk x 1.15 cu.ft/sk}}{0.02272\ \text{cu.ft/ft} + 0.0998\ \text{cu.ft/ft}} = 187.7\ \text{ft}$$

Displacement volume

Top of water behind cement

$$7025\ \text{ft} - 187.7\ \text{ft} - \frac{1.14\ \text{bbl x 5.61 cu.ft/bbl}}{0.02272\ \text{cu.ft/ft}} = 6555.8\ \text{ft}$$

(6555.8 x 0.02272) = 149 cu.ft

= 26.5 bbl

Once the cement has been balanced, the tubing is then pulled above the plug, the BOP rams are closed and the requisite amount of pressure is applied through the tubing in order to start the squeezing of the cement slurry through the perforations.

MAXIMUM ALLOWABLE SURFACE PRESSURE

The maximum surface pressure that is acceptable at any time while the job is in progress may be given by:

MASP = (g_f x depth) - (P_h at 7025 ft) + (Δp_f) - (safety factor)

where, g_f = fracture gradient, psi/ft

P_h = hydrostatic pressure, psi

Δp_f can be dismissed generally, hence being an extra safety factor

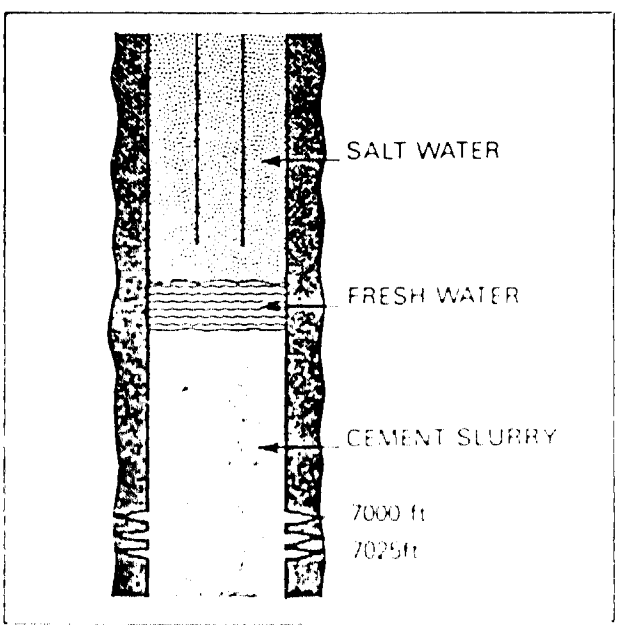


FIG. 8.7

The extent of the hydrostatic pressure present at the beginning of the squeezing may be calculated as follows:

Length of cement plug =

$$\frac{20 \text{ sk} \times 1.15 \text{ cu ft/sk}}{0.1305 \text{ cu ft/ft}} = 176 \text{ ft}$$

Length of water spacer =

$$\frac{(5 \text{ bbl} + 1.14 \text{ bbl})\ 5.61 \text{ cu ft/bbl}}{0.1305 \text{ cu ft/ft}} = 264 \text{ ft}$$

Length of column of brine =

$$(7025 - 176 - 264) = 6585 \text{ ft}$$

Therefore,

Total hydrostatic pressure =

$$0.052\ [(176 \times 15.8) + (264 \times 8.32) + (6585 \times 9.5)] = 3512 \text{ psi}$$

The maximum allowable surface pressure (MASP) when squeezing begins is therefore:

$$[(7025 \text{ ft} \times 0.7 \text{ psi/ft}) - (3512 \text{ psi}) - (500 \text{ psi})] = 906 \text{ psi}$$

The MASP at the end of the squeezing may be calculated as follows:

Cement volume inside the casing

$$= (20 - 4.84) \text{ sk} \times (1.15 \text{ cu ft/sk}) = 17.43 \text{ cu ft}$$

Length of cement column

$$= (17.43 \text{ cu ft})/(0.1305 \text{ cu ft/ft}) = 134 \text{ ft}$$

Hydrostatic pressure

$$= 0.052\ [(134 \times 15.8) + (264 \times 8.32) + (6627 \times 9.5)] = 3498 \text{ psi}$$

Hence, MASP (final)

$$= (7025 \times 0.7) - (3498) - (500) = 920 \text{ psi}$$

In this instance, with a comparatively low volume of cement to be squeezed, the difference between the hydrostatic pressure at the beginning and at the end of the job is not very significant and virtually impossible to monitor. There are cases, however, in which a plot of the MASP against the volume squeezed is of considerable importance — especially where such a plot can be used to determine the limits on the surface pressure at any given point in the job.

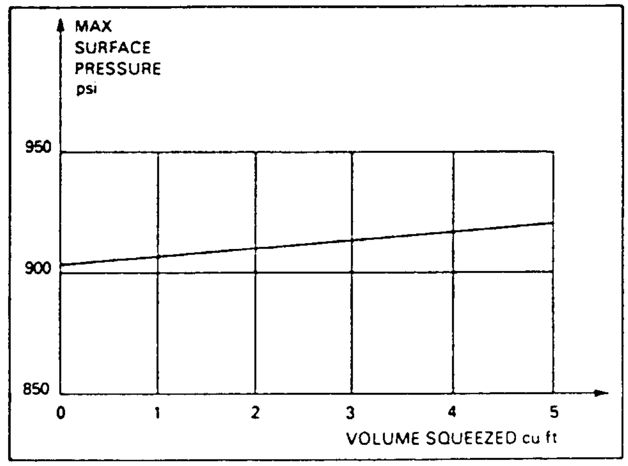


FIG. 8.8

SQUEEZING THROUGH A RETRIEVABLE PACKER OR CEMENT RETAINER

Wherever the packer is run with tail pipe and the cement slurry spotted in front of the perforations, the balancing of the cement plug and the surface pressure calculations are similar to those for Bradenhead squeezes.

In some operations, however, the cement is circulated down the hole with the packer's by-pass open; before the cement reaches the packer, the by-pass is closed causing the fluid ahead of the slurry to be squeezed into the formation. If this

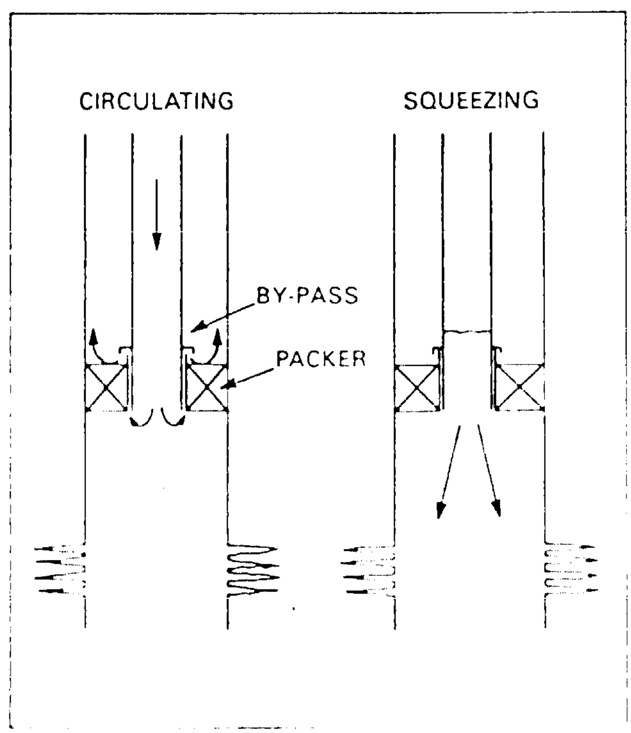


FIG. 8.9

operation is to succeed when using low pressure squeezing, the fluid ahead of the cement slurry must be clean and free of solids, so as to avoid plugging any perforations or channels ahead of the cement.

VOLUMES

The slurry volume should always be checked against the maximum prevailing hydrostatic pressures. The greatest hydrostatic column will exist at the moment the preflush comes into contact with the lower perforations.

Length of cement column:

$$\frac{20 \text{ sk x } 1.15 \text{ cu ft/sk}}{0.02272 \text{ cu ft/ft}} = 1012 \text{ ft}$$

Water ahead of the cement slurry = 3 bbl

Water behind the cement slurry = 3 bbl

The volume of casing below the packer (packer at 6900 ft) = 125 ft x 0.1305 cu ft/ft = 16.31 cu ft
= 2.91 bbl (3 bbl, say)

The length of the column of water in the tubing

$$= \frac{3 \text{ bbl x } 5.6 \text{ cu ft/bbl}}{0.02272} = 740 \text{ ft}$$

Hydrostatic pressure, therefore,

= 0.052 [(125 x 8.32) + (1012 x 15.8) + (740 x 8.32) + (5148 x 9.5)]
= 3749 psi

Formation fracture pressure is

7025 ft x 0.7 psi/ft = 4917 psi

The calculated hydrostatic pressure is therefore 1,170 psi below the formation fracture pressure.

In our example, therefore.

Packer Placement

The packer will be placed 100 ft above the perforations at 6900 ft and the by-pass left open.

Fluid Volumes

The volumes of fluid shown below will be pumped in the following order, with the by-pass remaining open until the fresh water preflush comes within one bbl of the bottom of the packer.

Fresh water preflush = 3.00 bbl *(1)*

Cement slurry

$$\frac{20 \text{ sk x } 1.15 \text{ cu ft/sk}}{5.61 \text{ cu ft/bbl}} = 4.10 \text{ bbl} \quad (2)$$

Fresh water behind = 3.00 bbl *(3)*

10.10 bbl total

Displacement Brine

$$\text{Tbg Vol} = \frac{6900 \text{ ft x } 0.02272 \text{ cu.ft/ft.}}{5.61 \text{ cu.ft/bbl}} = 27.94 \text{ bbl}$$

Vol. of brine to be pumped to leave the fresh water 1 bbl from the packer = (27.94 - 10.10 - 1.00)bbl
= 16.84
say, 17 bbl *(4)*

Once the 17 bbl of brine have been pumped (bringing the preflush water to within 1 bbl of the packer), the by-pass is closed and we can proceed with the squeeze (*fig.8.10*).

Fresh water preflush displaced from tubing

The greatest hydrostatic pressure is applied to the formation at the point when all the leading fresh water has been displaced from the tubing. The total volume of brine required to achieve this displacement is

(17 + 1 + 3) bbl = 20.9 bbl (*see fig.8.11*)

Cement at perforations

The cement will reach the perforations when 2.9 bbl of it (the volume of the casing below the packer) has been pumped from the tubing. The total volume of brine needed to be pumped for the cement to reach the perforations, therefore, is 20.9 + 2.9 = 23.8 bbl (*see fig.8.12*).

All the cement will be displaced from the tubing

when: 23.8 bbl + 1.2 bbl = 25.0 bbl of brine have been pumped (*see fig.8.13*)

Maximum displacement

The process of squeezing should stop when there is about 20 ft of cement still standing above the perforations (Presuming that final pressure has not been reached in advance of this point)

(7 000 ft - 6900 ft - 20 ft) = 80 ft

$$\frac{80 \text{ ft x } 0.1305 \text{ cu ft/ft}}{5.61 \text{ cu ft/bbl}} = 1.9 \text{ bbl}$$

One should therefore, pump 1.9 bbl of additional brine (if possible)

In consequence we can write that the maximum volume of brine that can be pumped before stopping is:

= (25.0 + 1.9) bbl
= 26.9 bbl (*see fig.8.14*)

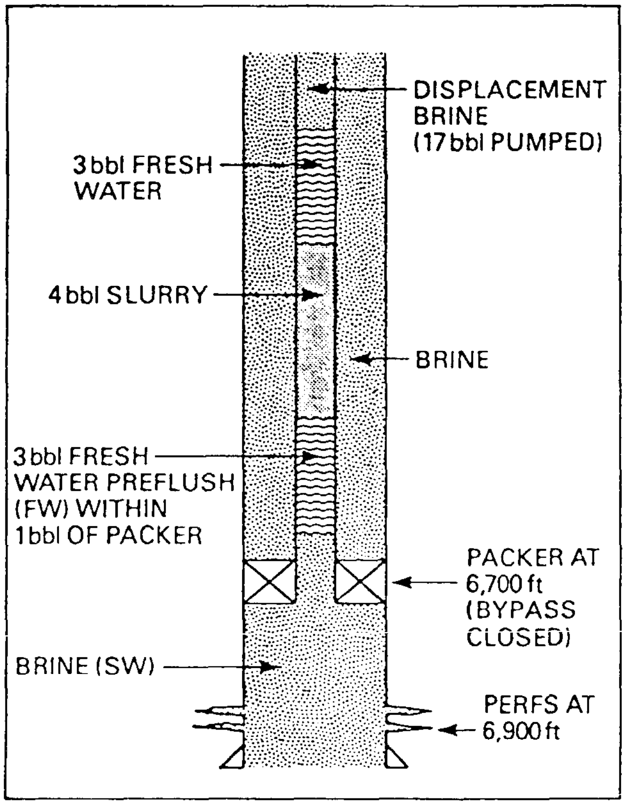


FIG. 8.10

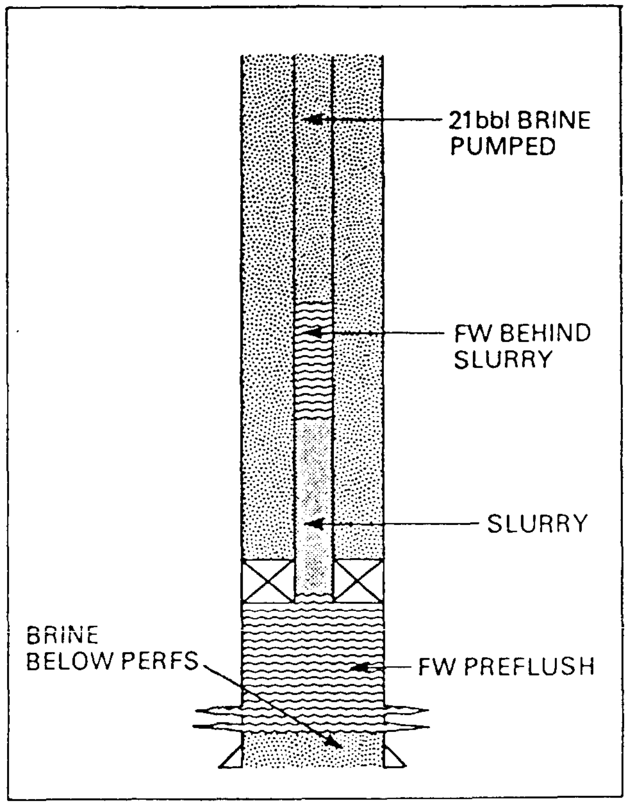


FIG. 8.11

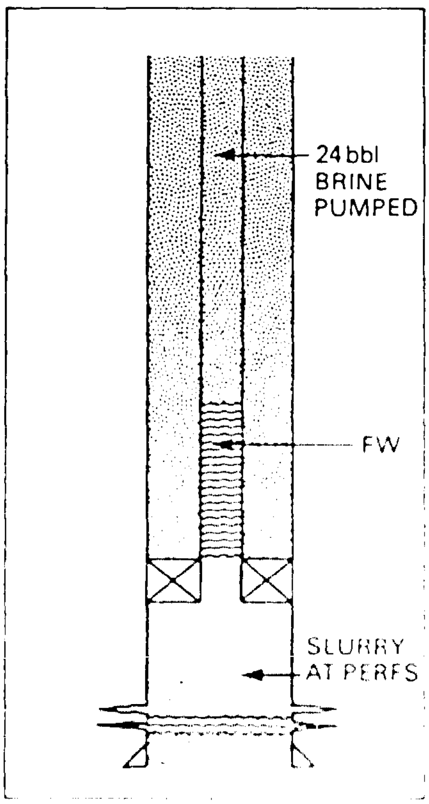


FIG. 8.12

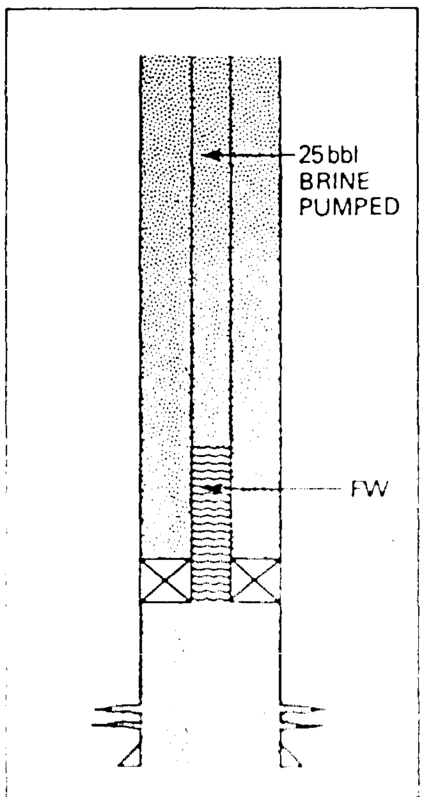


FIG. 8.13

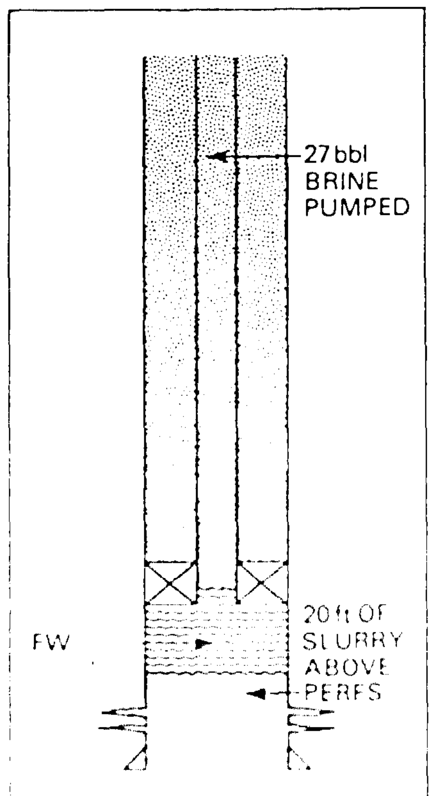


FIG. 8.14

MAXIMUM ALLOWABLE SURFACE PRESSURE

When involved in low pressure squeezing, it is important to remember that the hydrostatic pressure inside the tubing is applied to the formation immediately the packer by-pass is closed.

The maximum allowable surface pressure, (neglecting friction pressures) is (as previously):

MASP

$= (g_f \text{ x perf. depth}) - (\text{safety factor}) - (P_h \text{ at perfs})$

This varies according to the cumulative volume pumped into the tubing after the by-pass valve is closed.

CUMULATIVE VOLUME PUMPED AFTER CLOSING BYPASS	HYDROST PRESSURE TUBING			HYDROST PRESSURE CASING			TOTAL	MASP
	SW	FW	CMT	SW	FW	CMT		
bbl	psi	psi	psi	psi	psi	psi	psi	psi
0 *(fig 8.10)*	2177	640	832	62	–	–	3711	700
4 *(fig 8.11)*	2543	320	832	–	54	–	3749	670
7 *(fig 8.12)*	2897	320	242	–	–	103	3562	860
8 *(fig 8.13)*	3042	320	–	–	–	103	3465	950
10 *(fig 8.14)*	3269	122	–	–	35	37	3463	950

TABLE 8.4

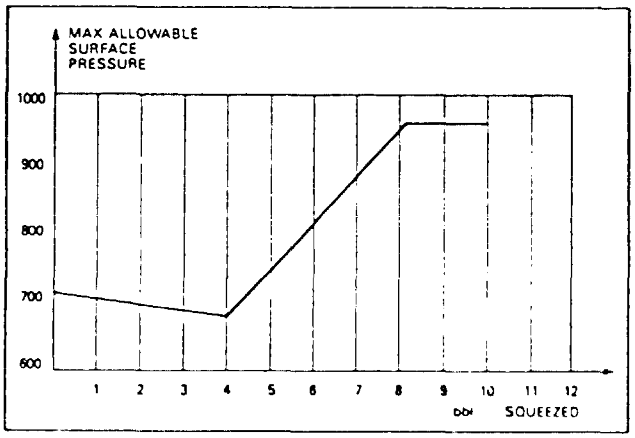


FIG. 8.15

The above graph (*fig 8.15*), made by plotting the Maximum Allowable Surface Pressure (*Table 8.4*) against the Cumulative Volume Pumped after closing the by-pass, can be used to monitor the maximum surface pressure during the job

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Appendix C
Plugback Cementing

C.1 Problem

Balance a 200-ft cement plug from 5,800 to 6,000 ft after drillpipe is removed.

C.2 Desired Information

1. Cement volume—cubic feet of slurry and number of sacks.
2. Cement column height and spacer column height with the drillpipe in the plug.
3. Spacer volume.
4. Mixing water volume (for cement, spacer, and 20-bbl cleanup).
5. Displacing fluid volume.

C.3 Well Conditions (see Fig. C-1)

Hole size—8.75 in.
Drillpipe size—4.5 in. OD, 16.60 lbm/ft.
Plug set—6,000 to 5,800 ft.
Mud in hole—water based, 12.8 lbm/gal.
Spacer—200 ft of fresh water.
Cement—API Class H.
Slurry weight—16.4 lbm/gal.

C.4 Calculations

1. *Cement volume.* Capacity of 8¾-in. hole = 0.4176* cu ft/ft.

Cement volume equals capacity factor times height of desired plug:

0.4176 cu ft/ft × 200 = 83.52 cu ft.

Cement volume equals API Class H at 16.4 lbm/gal = 1.06 cu ft/sack.

Sacks of cement equals cubic feet cement divided by cubic feet slurry per sack:

83.52 cu ft / 1.06 cu ft/sack = 78.79 sacks.

*Factors that are underlined were taken from cementing tables available from Halliburton Services, Duncan, OK.

2. *Height of cement plug with work string still in plug.* Equalization point formula:

$$h=\frac{N}{C+T},$$

where

h = height of balance cement column,

$$\frac{83.52 \text{ cu ft}}{0.3071 \text{ cu ft/ft}+0.07980 \text{ cu ft/ft}}$$

$=215.87$ cu ft,

N = required cement slurry (cubic feet), 78.79 sacks × 1.06 cu ft/sack = 83.52 cu ft,

C = cubic feet per linear foot of space between tubing (or drillpipe) and casing (or hole) found in the handbook tables under "Volume and Height," 0.3071 cu ft/ft, and

T = cubic feet per linear foot inside tubing (or drillpipe or casing) found in the handbook tables under "Capacity," 0.0798 cu ft/ft.

3. *Volume and height of spacer in the annulus with work string still in plug.* Annulus fill-up factor for 4½-in.-OD pipe in an 8¾-in. hole = 0.0547 bbl/ft.

Annulus volume of flush equals fill-up factor times required fill

0.0547 bbl/ft × 200 ft = 10.94 bbl

Determine the fill-up ratio between the height of fluid in the annulus and the height of fluid in the work string.

From handbook ("Volume and Height Between Casing, Drillpipe, and Hole"), height of fluid fill in annulus for 4½-in.-OD pipe in 8¾-in. hole = 18.2804 ft/bbl

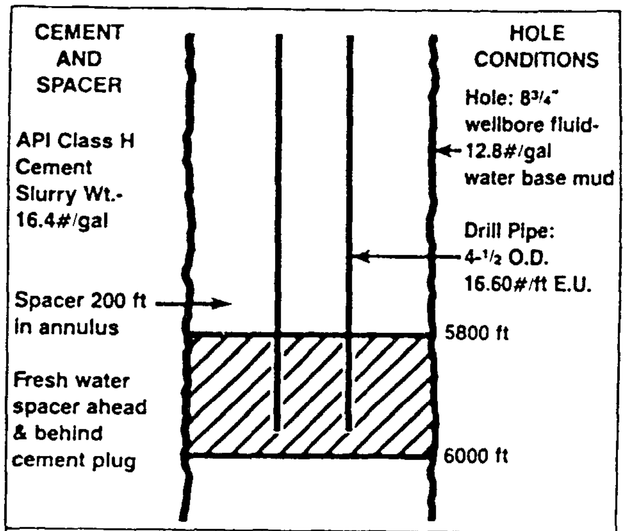

Fig. C-1—Plugging example.

From handbook ("Capacity"), height of fluid fill inside 4½-in., 16.60-lbm/ft EU drillpipe = 70.32 ft/bbl.

Height ratio formula: *R* equals the fill-up factor for the work string (feet per barrel) divided by the fill-up factor for the annulus (feet per barrel):

$$\frac{70.32 \text{ ft/bbl}}{18.2804 \text{ ft/bbl}} = 3.85.$$

Annulus volume divided by *R* equals tubing volume:

10.94 ÷ 3.85 = 2.84 bbl.

For this example, use 3 bbl of spacer behind the cement. This will change the volume of spacer to be pumped ahead of the cement plug.

New annulus volume equals tubing volume times fill-up ratio:

3 bbl × 3.85 = 11.55 bbl (round up to 12 bbl).

Spacer height should be equal inside and outside the work string. Spacer height equals volume of spacer times fill-up factor:

12 bbl × 18.2804 ft/bbl = 219 ft.

4. *Freshwater requirements (for cement-spacer and equipment cleanup).* Mixing water per sack of Class H cement at 16.4 lbm/gal = 4.3 gal/sack.

Mixing water equals gallons per sack times total sacks: 4.3 × 78.79 = 339 gal.

339 gal ÷ 42 gal/bbl = 8.07 bbl.

Water for spacer equals spacer ahead plus spacer behind cement plug:

10.94 + 2.84 = 13.78 bbl.

Total fresh water equals mixing water plus spacer water plus cleanup water:

8.07 bbl + 13.75 bbl

+20 bbl (cleanup water variable)

= 41.82 bbl total.

5. *Displacement volume—capacity of mud behind spacer and cement.* The displacement footage required behind the spacer and cement equals total work string depth minus (height of spacer plus height of cement with work string still in plug).

Displacement footage = 6,000 ft − (215.87 + 200 ft)
= 5,584 ft.

Capacity factor:

4½-in. EU 16.60 lbm/ft drillpipe = 0.01422 bbl/ft.

Displacement volume equals capacity factor of work string times displacement footage:

0.01422 bbl/ft × 5,584 ft = 79.41 bbl.

C.5 Balanced Plug for Whipstock

Set a cement plug from 5,600 to 6,000 ft for directional drilling (whipstock).

C.6 Desired Information

1. Sacks of cement.
2. Height of cement with drillpipe and tubing in place.
3. Height of water in annulus and barrels of water in drillpipe and tubing.
4. Total water (including mixing water, spacer, flush, and 20-bbl cleanup).
5. Barrels of displaced fluid.

C.7 Conditions

Cement. Class A cement mixed at a slurry density of 15.6 lbm/gal; run 30 bbl of fresh water ahead of the cement plug; and run 500 ft of 2⅞-in. OD, 4.70-lbm/ft EUE tubing with scratchers and centralizers attached to the bottom of the drillpipe.

Hole. 9½-in. drilled hole washed out to an average 12-in. hole from 5,430 to 6,145 ft; 3½-in.-OD, 13.30-lbm/ft EU drillpipe; and wellbore fluid is 10.5-lbm/gal native mud.

C.8 Calculations

1. *Volume of cement.* From handbook: capacity factor for a 12-in. hole equals 0.7854 cu ft/ft.

Cement volume equals capacity factor times height of desired plug.

0.7854 cu ft/ft × 400 ft = 314.16 cu ft.

Class A cement mixed at 15.6 lbm/gal = 1.18 cu ft/sack.

Sacks of cement equals cubic feet of cement divided by cubic feet of slurry per sack

314.16 cu ft ÷ 1.18 cu ft/sack = 266.24 sacks

2. *Height of cement plug with work string still in plug.* Equalization point formula:

$$h_c = -\frac{N}{C+T},$$

where

h_b = height of balance column,

$$\frac{314 \text{ cu ft}}{0.7546 \text{ cu ft/ft} + 0.02171 \text{ cu ft/ft}}$$

$$= 404.48 \text{ ft},$$

N = required cement slurry: 314.16 cu ft,

C = space between tubing (or drillpipe and casing/hole): 12-in. hole capacity factor minus 2⅞-in. hole capacity factor = 0.7546 cu ft/ft, and

T = cubic feet per linear foot inside tubing or drillpipe or casing = 0.02171 cu ft/ft.

3. *Volume and height of flush with work string still in plug.* Calculate the footage of a 2⅞-in. work string that is not covered by cement by subtracting the height of cement with work string in the plug from the total length of 2⅞-in. tail pipe.

Tubing not covered with cement = 500 − 404.68 ft = 95.32 ft, where h = 411.73.

Calculate the volume of flush in the 2⅞ × 12-in. annulus and the volume of flush in the 2⅞-in. work string.

Annulus capacity factor = 0.1399 bbl/ft − 0.0055 bbl/ft.

95.32 ft × 0.1344 bbl/ft = 12.81 bbl freshwater flush in annulus.

95.32 ft × 0.00387 bbl/ft = 0.37 freshwater flush in tubing.

Annulus volume 3½-in. drillpipe and 12-in. hole (5,430 to 5,500 ft).

Annulus volume (in barrels per foot) equals volume of 12-in. hole (barrels per foot) minus volume of 3½-in. hole (barrels per foot):

0.1399 bbl/ft − 0.0119 bbl/ft = 0.128 bbl/ft.

Barrels of flush between 5,430 and 5,500 ft = (5,500 ft − 5,430 ft) × 0.128 bbl/ft = 8.96 bbl.

Calculate the remaining flush that will have to be balanced. Total flush minus flush used with 2⅞-in. annulus work string equals remaining flush for 3½-in. drillpipe inside 12-in. annulus: 30 bbl − 12.8 bbl − 8.96 = 8.24 bbl freshwater flush in annulus between 3½-in. drillpipe inside 9½-in. hole.

Fill-up factor (feet per barrel) 3½-in. drillpipe inside 9½-in. hole = 13.1976 ft/bbl (handbook volume and height between casing, drillpipe, and hole):

13.1976 ft/bbl × 8.23 bbl = 108.62 ft.

(70 ft + 108.62 ft) × 0.00742 bbl/ft

= 1.33 bbl freshwater flush in drillpipe.

Total freshwater flush = annulus freshwater flush + 2⅞-in. freshwater flush volume + 3½-in. freshwater flush volume.

Total freshwater flush volume = 30 bbl + 0.37 bbl + 1.33 bbl = 31.7 bbl.

4. *Freshwater requirements.* Mixing water per sack of Class A cement at 15.6 lbm/gal = 5.2 gal/sack.

Mixing water equals water-per-sack factor times total sacks:

5.2 gal/sack × 266.24 sacks = 1,384.448 gal.

Mixing water = 1,384.448 gal ÷ 42.00 gal/bbl = 32.96 bbl.

Total freshwater flush volume = 31.7 bbl.

Cleanup or washup = 20 bbl.

Total fresh water = 32.96 bbl + 31.7 bbl + 20 bbl = 84.66 bbl.

5. *Displacement volume—capacity of mud behind spacer and cement.* Displacement footage equals total work string depth minus (height of spacer plus height of cement with work string still in the plug):

6,000 ft − (95.32 ft + 70.00 ft + 108.60 ft + 404.68 ft)

= 5,321.38 ft.

Capacity factor: 3½-in. EU, 13.30-lbm/ft drillpipe = 0.00742 bbl/ft.

Displacement volume equals capacity factor of work string times displacement footage minus 0.00742 bbl/ft × 5,321.38 ft = 39.48 bbl.

5.6 IMPORTANT POINTS

SELECTION OF CEMENTING PROCEDURES

1. **CEMENT MIXING PROCEDURES**

   o Importance of proper mixing

     - Proper proportions
     - Predictable properties

   o Mixing water from purest available source

     - Potable water recommended
     - Clear water suitable

   o Mixing Methods

     - Jet
     - Recirculating
     - Batch
     - Bulk

2. **CEMENT PLUG PLACEMENT METHODS**

   o Balance method
   o Cement retainer method
   o Two-plug method
   o Dump bailer method

3. **PLACEMENT OF MULTIPLE PLUGS**

   o Most jobs require multiple plugs
   o Each plug should set before next plug is placed (8 to 24 hours)
   o Should tag plug to verify location and setting
   o Recirculate plugging fluid before placing each plug (static condition)
   o Repeat procedure for each plug

4. **TOOLS AND MATERIALS TO ASSIST IN PLUG PLACEMENT**

   o Scratchers
   o Centralizers
   o Chemical washes
   o Spacers to prevent contamination

5. GUIDELINES TO ENSURE CEMENT PLUG QUALITY

- Circulate the hole sufficiently.
- Use wellbore fluid having a low yield point, low plastic viscosity, and sufficient weight.
- Establish and maintain static well conditions.
- Place cement plugs across a competent, hard formation.
- Precede the cement slurry with flush or spacer.
- Use a low water ratio cement (API Class A, C, G, or H).
- Use the tools necessary to minimize contamination.
- Carefully calculate cement, water, and displacement volumes.
- Place the cement plug with care, withdrawing pipe from plug slowly to minimize contamination.

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7.0 GLOSSARY

- A -

abandon: to cease efforts to produce oil or gas from a well (or inject fluids into a well). See **"temporary abandonment"** and **"permanent abandonment".**

accelerator: a material which accelerates or speeds up the normal rate of reaction between cement and water, resulting in an increase in the development of early strength, and, in some cases, a decrease in the setting time or thickening time.

annular: referring to the annulus.

annular pressure test: a test method used to demonstrate the mechanical integrity of casing, tubing, and packer in a conventional well configuration. When using the test, tubing and packer are set inside the casing string to be tested. Pressure is then applied to the liquid-filled casing/tubing annulus for a specified period of time. If a significant pressure drop occurs during the test period, then one of the well components (casing, tubing, or packer) is leaking.

annulus (or annular space): the space surrounding one cylinder within another cylinder. This term can refer to the space around a section of pipe within a larger pipe or borehole (e.g. the long string annulus is the space between the long string and the surrounding borehole).

balance method (cementing): involves the pumping of a desired quantity of cement slurry through drill pipe or tubing until the level of cement outside is equal to that inside the string. The drill pipe or tubing is then pulled slowly from the slurry, leaving the plug in place.

bit: cutting or boring element used in drilling operations.

borehole: the hole made by drilling or boring a well.

bridge: restricting objects placed in the well to provide an obstruction upon which cement plugs may be set.

bridge plug (BP): a mechanical plug which is run inside casing or tubing for the purpose of isolating or sealing off a zone from the upper section of the well.

brine disposal: the practice of disposing of highly saline waters produced in association with oil or natural gas.

brush plug: restricting object (brush) placed in the well to provide an obstruction upon which cement plugs may set.

bullhead pumping method: cement placement method by which cement is pumped directly into the casinghead.

cable-tool drilling: a method of drilling in which a weighted bit at the bottom of a cable falls against the formation being penetrated, thereby using a percussion action to break the rock. A bailer is used to retrieve the rock particles from the bottom of the hole.

caliper log: a well log which measures hole diameter. Also called a "section gauge," the multi-armed tool measures the corrosion of casing and tubing.

cased hole logging: refers to any log run to determine characteristics in subsurface zones already confined by casing; to determine well conditions, especially of cemented or perforated intervals; or to determine the condition of the casing itself.

casing: pipe, usually steel, used in oil wells to seal off fluids from the borehole and to prevent the walls of the hole from sloughing off or caving. API casing sizes range from 4 1/2 in. OD to 20 in. OD inclusive.

casing inspection log: a cased hole log which utilizes induced electrical current to detect corrosion or other damage in casing.

casing roller: a rugged tool composed of a mandrel with a series of eccentric roll surfaces, each of which is assembled with a series of heavy-duty rollers. The tool is used to restore buckled, collapsed, or deformed casing. A casing roller is run on tubing or drill pipe to the depth where casing is deformed, and is rotated slowly, which allows the rollers to contact all sides of casing.

casing shoe: a short, heavy section of steel pipe with a rounded bottom that is placed on the end of a casing string to assist in guiding casing into the hole. For purposes of this paper, this term refers to the bottom of the casing string.

casing stub: uppermost portion of casing, remaining in hole subsequent to cutting and pulling upper section of uncemented pipe.

cast iron bridge plug (CIBP): a mechanical plug composed of cast iron which is run on wireline inside casing for the purpose of permanently sealing off a zone from the upper section of the well. A CIBP must be drilled out for removal.

cement dump bailer: a cylindrical container with a valve that is used to release small batches of cement downhole.

cement evaluation log: a cased hole log which is used to measure cement quality. Cement evaluation logs consist of two major types: the **cement bond log (CBL)** and the **cement evaluation tool (CET)**. The cement bond log (CBL) measures the general extent of cement and its bonding quality through the induction of acoustic signals and observation of signal response at it passes through existing medium (e.g. fluid, pipe, cement, and formation). The cement evaluation tool (CET) uses a different measurement principle; the CET uses a pulse of ultrasonic energy to investigate the cement radially and measure cement existence and quality, casing diameter, casing roundness and tool eccentricity. It is able to provide data which the CBL cannot provide.

cement plug: a portion of cement placed at some point in the well to effect a sealing action.

cement retainer: a tool set in the casing or well during squeeze cementing and other remedial cementing jobs. The cement retainer tool is run on tubing and allows the passage of cement when valves are open. With tubing removed, the valves close, preventing the passage of cement below the tool.

cement retainer method: a method of cement placement by which cement is pumped through open valves of a retainer tool and into the hole. The tool is then set and the cement is forced by pressure into the exposed formation. Upon removing the tubing from the tool, valves close and cement can no longer pass through the tool, but is emplaced on top of the retainer, forming an additional cement plug.

cement slurry: the plastic fluid which is produced by the mixture of dry cementing materials with water.

cementing plugs: plugs which are used during cementing operations. There are several distinct types of cementing plugs. They are used to : (1) separate fluids used during the cementing process (e.g. mud, cement, displacement fluid, etc.); (2)

clean casings of fluids or particles which can contaminate cement; and (3) provide a seal or shutoff so that fluid cannot bypass the plug.

centralizers: guides which are attached to the outside of the casing and which serve to keep it centered in the hole. Centralizers are also used to maintain proper centralization of cased hole logging tools.

circulation: refers to the process by which a fluid is moved from and back to the same point (e.g. from the surface, through the wellbore, and back to the surface).

compressive strength: the degree of resistance of a material to force acting along one of the axis in a manner tending to crush it, usually expressed in pounds of force per square inch of surface affected.

confining zone: a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone.

conventional completion or operation: an injection well construction type having cemented surface casing, cemented long string casing, and injection tubing and packer which are set above the injection interval. In a conventional operation, fluids are injected through the injection tubing and into the injection zone. This is the predominant well construction for injection wells.

crossflow: refers to the movement of fluids from one zone to another.

- D -

dehydration: removal of free or combined water from a material.

densimeter: an automated device used to weigh drilling fluids and oilfield cements. The densimeter is installed in the discharge line between the mixing unit and the wellhead, and continuously records fluid weight throughout the operation.

dispersant: a cement additive which reduces the initial consistency of cement slurries.

dump-bailer: a cylindrical container with a valve that is used to release small batches of cement downhole.

dump-bailer method: a means of slurry deposition or fluid displacement usually in association with cementing or completion work.

- E -

enhanced oil recovery: injection of water, steam, gases or chemicals into underground reservoirs to cause oil to flow toward producing wells, thus permitting more recovery than would have been possible from natural pressure or pumping alone.

- F -

fishing: operations for the purpose of retrieving pipe, collars, junk, or other obstructions from the wellbore.

fishing magnet: a powerful permanent magnet designed to recover metallic objects lost in a well.

flocculation: the coagulation, coalescence or aggregation of finely divided suspended particles.

fluid density balance: a portable device which measures the density of a cement slurry under sufficient pressure to compress entrained air. It is believed to be a more accurate measurement than when the cement sample is taken directly from the mixing tub.

formation fluid: a fluid that naturally occurs in an underground geologic formation.

free point indicator tool: a tool designed to measure the amount of stretch in a string of stuck pipe, thereby, indicating the deepest point at which the pipe is free.

- G -

gel: a term used to designate highly colloidal, high-yielding, viscosity-building commercial clays, such as bentonite and attapulgite clays.

gelled water: water having a small to moderate percentage of bentonite added.

- H -

hopper: a device used to hold or feed fluid additives (e.g. dry cement and additives).

hydration: the chemical reaction between hydraulic cement and water forming new compounds most of which have strength-producing properties.

hydrostatic equilibrium: a static state (e.g. no fluid movement).

hydrostatic head the vertical distance of a column of liquid. Hydrostatic head is commonly expressed as "feet of liquid."

- I -

injection fluids: fluids injected via a well into an underground geologic formation.

injection packer: the device on the end of the injection tubing which, when set, isolates the injection fluids by forming a seal between the injection tubing/casing wall or injection tubing/borehole wall, while still allowing fluid movement to occur through its internal opening, or bore. In casing, packers are generally retrievable. In open hole, packers are generally permanent installations. See **"packer"**.

injection string: the entire length of the tubing or casing used to inject fluids into a well.

injection tubing: small diameter pipe used to inject fluids into a subsurface formation.

injection zone: the geological formation into which fluids are injected.

interformational flow: refers to the movement of fluids from one formation to another.

intermediate casing: the casing string between surface and long string casings frequently used to support and seal off problem sections encountered in a wellbore while drilling.

- J -

jet cutter: a tool used to sever pipe in a well. The tool severs the pipe through detonation of a specially shaped explosive, which generates horizontal cuts around the pipe.

jetted water: water forced through a "jet" or port.

junk retriever: a cylindrical tool used to retrieve metal debris lost in a well.

- L -

leaching: a process by which soluble materials are removed through contact with a liquid (e.g. washing out).

liner: in this paper, refers to a partial length pipe string extending from the bottom of the borehole to an elevation above the bottom of the previous casing string. A liner performs the same function as production casing in sealing off productive zones and water bearing formations. A liner may or may not be cemented in place. Although not used as such in this paper, the term "liner" may also refer to a smaller diameter casing run inside of existing casing, extending from the surface to the top of the productive zone. It may or may not be cemented, and is frequently run when the existing casing string develops leaks or mechanical problems.

liquid hydrocarbon storage: the storage of hydrocarbons (which are liquid at standard temperature and pressure) in porous underground geologic formations.

long string casing: the casing string that runs from the surface to the total depth of the well (or to just above the target zone, if an open hole completion). It is generally referred to as the injection or production casing, and normally contains injection tubing and packer, or production tubing.

lost circulation: the loss of quantities of fluids to a formation, evidenced by the complete or partial failure of the fluid to return to the surface as it is being circulated in the well.

- M -

Marsh funnel viscosity: commonly called the funnel viscosity. The Marsh funnel viscosity is reported as the number of seconds required for a given fluid to flow 1 qt. through the Marsh funnel.

mechanical integrity: an injection well has "mechanical integrity" if its state of repair is such that no significant leaks are present in the well's tubing, packer, or casing; and there is no significant fluid movement into a USDW through vertical channels adjacent to the injection wellbore (e.g. cement).

mechanical plug: a plug which is generally run inside casing or tubing for the purpose of isolating or sealing off a zone from the upper section of the well.

milling: the process by which a mill is used to cut or grind metal objects in a well. A mill is a downhole tool with rough, sharp, extremely hard cutting surfaces.

mud: a fluid circulated through a well during both drilling and remedial operations. Mud is composed of liquids and solids and is used to: (a) cool and lubricate the drill bit, (b) suspend formation cuttings for ease in bringing them to the surface, and (c) provide a hydrostatic fluid column which can be "weighted" to assist in pressure control and stability of the wellbore. See **"gel"**.

mud balance: a balance used to measure fluid density. In using a mud balance during cementing, samples are selectively taken from the mixing tub and vibrated to remove any finely entrapped air bubbles from the mixer.

mudcake: the solid material deposited along the wall of the hole resulting from filtration of the liquid part of the drilling fluid or cement slurry into the formation.

- N -

noise log: a cased hole log which measures the borehole audio signals caused by the flow of fluids.

- O -

open hole: portion of the well in which casing has not been set.

overshot tool: a fishing tool which is attached to tubing or drill pipe and lowered over the outside wall of pipe lost or stuck in the wellbore. A friction device in the overshot firmly grips the pipe, allowing the stuck pipe to be pulled from the well.

- P -

P&A - abbr: plug and abandon.

packer: downhole equipment consisting of a sealing device, a holding or setting device, and an inside passage for fluids. It is used to block the flow of fluids through the annular space between the tubing and the borehole wall (or between tubing and casing) by sealing off the space between them.

paraffin: a wax-like substance which is deposited from some crude oils as they flow through the wellbore.

perforations: holes which are shot in the casing string either for the purpose of producing fluids from, or injecting fluids into a formation, or for the purpose of performing remedial cementing operations. Holes are formed in the casing by a perforating gun, which is an explosive device utilizing bullets or shaped charges.

permanent abandonment: to place cement plugs across critical zones in a well to abandon it.

permeability: a property of geologic formations whereby fluid movement can occur through the pore spaces, fissures, and or fractures in the rock.

plastic viscosity: a measure of the internal resistance to fluid flow attributable to the amount, type, and size of solids present in a given fluid.

plug and abandon: See **"permanent abandonment"**.

plug-back: to place mechanical and/or cement plug in or near the bottom of a well to isolate a lower zone from the upper portion of the well.

plug-back total depth (PBTD): the depth at which the well is plugged back.

potable water: water suitable for drinking or cooking purposes from both health and aesthetic considerations.

production casing: see **"long string casing"**.

- R -

radioactive tracer survey: a survey commonly performed in injection wells to monitor the movement of injection fluids in the wellbore. The tool injects a slug of radioactive material into the injection fluid stream and, through detectors on the tool, traces its movement throughout the wellbore.

reservoir: a subsurface porous and permeable rock body that contains oil and/or gas. Most reservoir rocks are limestones, dolomites, sandstones and/or a combination of these.

retarder: a chemical which is added to cements or slurries to lengthen thickening time.

retrievable bridge plug (RBP): a retrievable mechanical plug which is run inside casing or tubing for the purpose of isolating a zone from the portions of the well above the zone. A RBP is designed so that it can be taken out of the well with ease.

retrievable packer: a packer which, after set, can be retrieved from the hole by reversing the setting process. Most packers used in conventionally completed injection wells are retrievable. See **"packer"**.

reverse circulation: a process in which the normal course of fluid circulation is reversed. In reverse circulation, fluid is pumped down the annulus and up and out of the tubing or pipe.

rotary drilling: the method of drilling wells that depends on the rotation of a bit attached to a column of drill pipe to cut the rock. A fluid is circulated to remove the cuttings.

- S -

sack: standard package for cement (94 lb. of dry cement). This term is used informally as a measurement for the amount of dry cement used to mix a cement slurry.

scratcher: a device fastened to casing which aids in removal of mudcake from the annulus while the pipe is being moved during the cementing operation.

screen: a well screen serves as the intake section of a well. The screen is a pipe with small holes or slots that allow fluids to enter the well, but prevent or minimize the entry of sand particles into the wellbore.

secondary recovery: any method by which an essentially depleted reservoir is restored to a producing status by the injection of liquid or gases into the reservoir. This process produces energy, which enables the movement of reserves through the reservoir and to the producing wellbore.

shoot off: refers to tubing or casing severance. This can be performed by: (a) an explosive charge or (b) a chemical which "cuts" the metal.

shut-in: to close a valve, or shut off a pump to cease injection into, or production from a well.

slurry: suspension of solids in water, oil or mixture of both.

slurry yield: the volume of slurry which is produced from one sack of cement (e.g. 1 sack of Class A cement mixed with 5.2 gallons of water produces a slurry yield of 1.18 ft^3 of slurry/sack of cement).

spacer: a fluid which is used to separate two incompatible fluids, while being compatible with both.

spear: a tool used to retrieve pipe lost in a well. The spear is lowered into the lost pipe and, through a series of mechanical movements, grips the inside wall of the lost pipe, enabling its retrieval from the well.

squeeze cementing: a remedial cementing operation in which pressure is applied to "squeeze" or force cement into or against a formation through holes or perforations in the casing string.

static fluid level: the level to which reservoir fluids rise when the well is shut-in. This fluid level can be used to estimate the reservoir pressure. See **"fluid level"**.

string: refers to the entire length of casing, tubing, or drill pipe (e.g. the casing string, etc.).

surface casing: the first string of casing to be set in a well. Its principal purpose is to protect fresh water sands.

swaging tool: a tool used to straighten damaged or collapsed casing in a well.

TA - abbr: temporarily abandon

TDS - abbr: total dissolved solids

temporary abandonment: to cease operations on an oil or gas well without permanently plugging. Some wells are "temporarily abandoned" by shutting the well in. Others are "temporarily abandoned" by subsurface equipment removal and surface valve shut-in, etc. Future considerations for the utility of the well often contribute to the decision to delay permanent plugging and abandonment.

temperature survey: an operation to determine temperatures at various depths in the hole. The results of the survey are often used to identify suspected fluid entry into the wellbore.

tertiary recovery: a term which refers to enhanced oil recovery methods other than waterflooding, especially when steam, gases, or chemicals are used to provide the recovery mechanism.

total depth (TD): the maximum depth reached in a well.

tubing: small diameter pipe run in a well to provide a conduit for the injection or production of fluids.

tubular goods: any kind of pipe. Oilfield tubular goods include tubing, casing, drill pipe, and line pipe.

two-plug method: a means of placing a plug with less likelihood of overdisplacing or contaminating. Wiper plugs are run above and below the cement slurry. A plug catcher tool, run on the bottom of the string, seats the top plug and indicates that the cement has been placed at the desired depth.

- U -

uncased hole: that portion of the well which is not covered by a string of casing.

unconventional completion: any completion type that does not conform to a conventional completion type. See **"conventional completion"**.

- V -

viscosity: the internal resistance offered by a fluid to flow. This phenomenon is attributable to the attractions between molecules of a liquid, and is a measure of the combined effects of adhesion and cohesion to the effects of suspended particles, and to the liquid environment. The greater this resistance, the greater the viscosity.

- W -

water loss: the volume of water filtrate lost to the permeable material due to the process of filtration.

waterflooding: one method of enhanced recovery in which water is injected into an oil reservoir to push additional oil through the reservoir rock and into the producing wellbores.

wellbore: the hole drilled. This can refer to cased or uncased holes.

wiper plug: a rubber device which fits the internal diameter of a pipe string and is used in cementing operations. When inserted ahead of cement, the wiper plug wipes drilling fluid off the internal casing walls to prevent cement contamination. When inserted after the cement, the plug wipes cement off the casing walls and lands in a special fitting, which provides a surface pressure indication that the cementing operation is complete.

wireline: a slender, wire-wrapped electric line used to run equipment and tools in and out of a well. A wireline is generally 3/8 in. to 3/4 in. in diameter and is frequently used for well logging, perforating, etc.

workover fluid: fluid used during workover operations (e.g. circulation or drilling fluid used during remediation).

- Y -

yield point: the resistance to initial flow, or the stress required to initiate fluid movement.