IADC DRILLING SERIES

DRILLERS KNOWLEDGE BOOK

Creative solutions for today's drilling challenges

1ST EDITION

by

Leon Robinson, PhD,

and

Juan Garcia

Drillers Knowledge Book by Leon Robinson, PhD, and Juan Garcia

ISBN: 978-0-9909049-8-4 — First edition, first printing

International Association of Drilling Contractors
10370 Richmond Avenue, Suite 760
Houston, Texas 77042
USA

bookstore@iadc.org; +1 713 292 1945

About The Drillers Knowledge Book

This book is designed to provide accurate and authoritative information in regard to the subject matter covered, and for the general information and education of the reader. Although the author and publisher believe the information presented is accurate as of the date of publication, each reader is responsible for his own reliance, reasonable or otherwise, on the information presented. If professional engineering expertise is required, the services of a competent individual or firm should be sought. Neither the author nor the publisher warrant or guarantee that application of any theory, concept, method, or action described in this book will lead to the result desired by the reader.

This book was prepared under the auspices of the IADC Technical Publications Committee as part of the IADC Drilling Series. The IADC Drilling Series is a collection of books covering key topics that the drilling engineer needs to know. For more information, go to www.IADC.org/technical-publications-committee/.

Other books in the Drilling Series include:

Well Cementing Operations, Ron Sweatman, IADC, 2015

Underbalanced Drilling: Limits and Extremes, Bill Rehm, et al, Gulf Publishing Company, 2012

Managed Pressure Drilling, Bill Rehm, et al, Gulf Publishing Company, 2008

Casing and Liners for Drilling and Completion, Ted G. Byrom, Gulf Publishing Company, 2007

Also published by IADC:

IADC Drilling Manual, 12th edition, 2015

IADC Deepwater Well Control Guidelines, 2nd edition, 2015

IADC Health, Safety and Environmental Guidelines, 2015

Visit www.IADC.org/bookstore

Visit www.IADC.org/ebookstore

INTRODUCTION & PREFACE

by Leon Robinson, PhD, and Juan Garcia

This book is written for the experienced drilling engineer and field/drilling supervisor. Many books are available that discuss the fundamentals of drilling, procedures, and equipment. These subjects are well covered within the industry and will be assumed to be part of the experience level needed to apply procedures described here. The discussion of these subjects will concentrate on field-proven techniques and procedures necessary for a drilling rig to drill at its maximum potential and to eliminate trouble time and costs that delay drilling and increase risk.

One of the objectives of this book is to explain how a well is optimally designed and the way in which the operations should be properly executed. Planning for contingencies and being prepared for handling serious well situations is also part of a good well plan. The recommendations for well design planning and procedures presented are based on and supported by solid technical facts, scientific principles, and from laboratory work, studies and actual field experience. The proposals are not the product of arbitrary preferences. The approach is to present how a job should be done and to explain why it is recommended.

Another objective of this book is to promote, encourage and emphasize the importance of communications and sharing of experiences between engineers and field supervisors. This is important both in planning a well or a critical procedure, and when executing it out in the field. The field supervisor should understand why a given procedure is indicated and the engineer should ensure that the field supervisor has provided input to the plan, has no operational reservations about the plan, and is prepared to carry it out without flaws.

The material is structured so that the first two chapters cover the subject of well design planning. Subsequent chapters will present several operational procedures used to apply various technologies to enhance a wide variety of field operations aimed at continuous improvement of well performance.

After the well is properly designed and a drilling rig is designated to drill the well, many procedures can be used so that the rig will perform safely and efficiently to its maximum potential. Every rig has a limit on various aspects of the drilling operation. Each rig can have the drilling fluid hydraulics adjusted so that the fluid strikes the bottom of the borehole with the largest force possible or the maximum hydraulic power at the bit nozzles. After the proper standpipe pressure and flow rate are determined, the flounder point of the drill bit can be determined with the correct weight on bit and rotary speed. It is also important that the cuttings can be brought to the surface without degradation. These and many other procedures are discussed and demonstrated using examples. Most cannot be developed or decided before drilling begins and measurements can be made at the rig to provide the mechanism for proper calculations.

The authors would like to thank the many members of the IADC Technical Publications Committee who have spent many hours reading, editing, and critiquing this book. They would also like to thank some who have also made significant contributions to the material in the book. They are: Stan Christman, John Barker, Fred Dupriest, Marty Smith, Dr. Arash Haghshenas, Terry Howard and Edward Garay. The material represents technology developed during our careers — or over 100 years of drilling experience.

INTRODUCTION TO WELL DESIGN

by Leon Robinson, PhD, and Juan Garcia

Most things done right start with a good plan based on good, solid facts. In the case of technical endeavors, this requires using the best technology available, driven by practical experience. This is particularly applicable when dealing with complex subjects where all the critical data is not always available. In these cases, it is especially important to formulate a plan that not only considers all of the data available, but also allows for contingencies for anomalies that may affect the success of the plan, and more importantly the safety of those that are carrying out the plan.

Planning a well and drilling it safely and effectively is an excellent example where all of these elements need to be considered in order for the job to be done right. When planning an exploration well this is certainly the case, but even in appraisal or development wells often no two wells are exactly alike and surprises can occur at any time.

Well design planning, as described in this book, will address well architecture (how casing shoe setting depths and casing sizes are determined), well construction design (selecting when to use a long casing string vs. a liner) and the procedures needed to case-off (Isolate) each section of hole as a well is drilled towards its final objective. The first two chapters use complex well examples to describe a process used to determine the best way to case off and cement a given section of hole, as driven by wellbore conditions, section objectives, final well utility and risk/cost trade offs.

The subject of tubular products design (establishing performance ratings), which involves the principles and equations used for selection of weights, grades and connections to meet well operational pressures and loads, is the subject of several good books and will not be addressed here. An excellent book on this subject is one by Ted Byrom, entitled "Casing and Liners for Drilling and Completion" (Gulf Publishing, 2007; published under the auspices of the IADC Technical Publications Committee). The Byrom book was used as reference material to support the methodology for selecting materials based on API standards as available from many manufacturers.

The pressure and load design requirements criteria used in the examples in this book are based on the authors' experience and practice over the years and in most cases are similar to those presented in the Byrom book. Where the design approach is significantly different, it is so noted. Most major operating companies have their own casing design manuals for selecting safety factors, weights and grades of casing to meet anticipated load conditions for their well designs. Guidelines presented in the Byrom book as relates to safety factors, acceptable clearances between strings and well configurations are consistent with the authors' and were used as a guide for the examples presented.

DRILLERS KNOWLEDGE BOOK

TABLE OF CONTENTS

Chapter 1
Well Architecture Design

TABLE OF CONTENTS

1.1 INTRODUCTION

Well architecture design as defined in this chapter involves the determination of pipe setting depths and sizes for a deep vertical or low angle directional, abnormally pressured well, as driven by several factors including:

- Well depth;
- Desired final well tubing and production casing size (well utility);
- Depth vs formation pressure and fracture gradient profiles;
- Well hazards and anomalies;
- Regulations.

High-angle and horizontal well architecture design is not specifically addressed by the example well that will be used in this chapter. In horizontal wells, casing configurations, shoe depths and casing sizes are driven by both fracture gradient limitations at the farthest reach of the horizontal productive section and the need to sustain a high circulating mud weight to maintain wellbore stability in the long wellbore. In a horizontal drilled section, the height and weight of the rock above (overburden) is fixed. Therefore, the fracture gradient in a horizontal drilled section remains fairly constant over its length. Consequently, the length of the horizontal section that can be drilled will be limited by the fracture gradient at the end of the wellbore. When drilling, as the horizontal section of hole gets longer, the combination of the mud weight and the circulating pressure drop in the annulus (ECD) increases to a maximum at the end of the hole section below the bit. Therefore, when the ECD begins to approach the fracture capacity at the furthest point in the well, drilling must stop. The size of the casings set just prior to drilling the horizontal section, and, therefore, also the hole size that can be drilled, will determine what circulating rate ECD and mud weight combined circulating pressure at the end of the drilled section will be. Comparing the combined circulating pressure to the fracture capacity of the hole will then establish the size of the casings that must be set at the starting point of the horizontal section in order to achieve drilling the desired length of horizontal section. Although horizontal well architecture design is not addressed in this chapter, Chapter 2 on well construction design will address horizontal completions.

The most important information that is needed to develop a well plan is the pore pressure and fracture gradient versus depth data for the area. The amount and quality of the data that is available to develop these curves will vary with the geologic and geophysical knowledge of the area being drilled, including offset well information. The pore pressure curves that are generated from the available information are used to determine the mud weight needed to control the formation pressures while drilling. The fracture gradient curves are used to help establish the upper limit of mud weight allowed without fracturing the lowest stress/integrity formations in the hole section being drilled. The process of comparing required mud weight to drill deeper vs the risk of fracturing the lower stress formations in the interval is then used to determine where casing must be set to cover the lower integrity zones before drilling deeper where higher mud weights are required.

1.2 Building the pore pressure and frac gradient curves

In some cases, such as when drilling a rank wildcat, offset well information may not exist, and seismic and regional geological data combined with other similar field analogs is all that is available. For many years, the industry has had methods to process this data to result in a pore-pressure prediction. While this process requires substantial capability, it is possible, available and commonly used. Models exist today to permit calculations of fracture gradient in most of the world's geologic basins. In any case, with this data, the geologists and engineers ultimately produce a set of anticipated pore pressure and fracture gradient vs depth curves.

Scientists believe, and earth studies support, the theory that the Earth was formed in a marine environment; and that the pressures in fluid trapped in permeable and porous subterranean formations generally increase with depth. These fluids and materials including saltwater, dead plants, animals and microorganisms were buried along with sand, clay and other rock materials and compressed by the increasing weight of long term deposition of layers of the rock materials above. These layers of material are called overburden (as introduced above), and are the results of the way they were deposited and buried as the earth was formed over billions of years. It is also believed that the decomposition of the plants and animals buried under intense pressure from the overburden and heat ultimately became oil and gas. This oil and gas or trapped saltwater then fills the voids or fractures between the particles in the buried rocks. The deeper the formation is buried, the greater the weight of the rock above and therefore the greater the compaction and the trapped fluid's pressure. In some cases, however, anomalies can exist where trapped fluids and gas have escaped via fractures, faults or permeable formation paths toward the surface or to other originally lower-pressured formations. When this happens it will result in a pressure reversal. A pressure reversal is when a lower-pressure formation exists below a higher-pressure formation, or when a higher pressure than expected is encountered at shallower depths in a well.

The greater overburden weight that occurs with depth also causes the rocks to be denser, stronger and under higher stress, which results in increasing fracture strength capacity, as the rocks are buried at deeper horizons. Typically, the fracture gradient strength vs depth curve increases rapidly at shallow depths as the rocks become increasingly com-

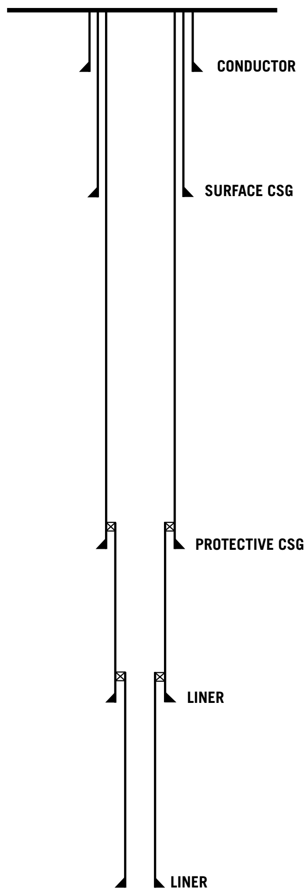


Figure 1-1: Typical deep well profile.

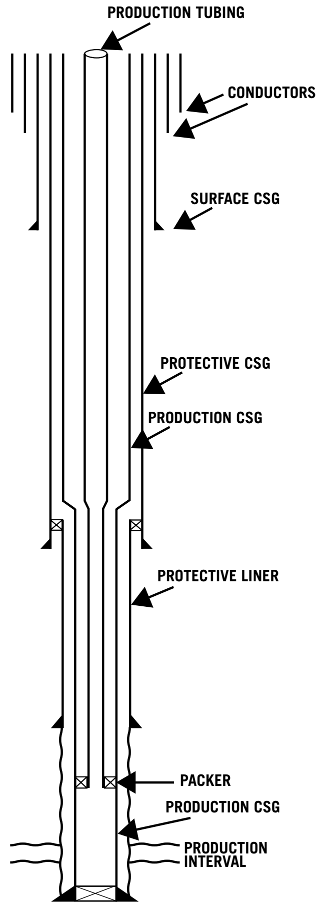


Figure 1-2: Typical completed deep well architecture.

pacted by the overburden. At deeper depth, the slope of the curve, or rate of fracture-gradient increase vs depth, declines as the rocks begin to reach a point where further compaction is not possible. Setting casing in the upper part of the hole will yield the greatest increase in frac gradient to help drill the well down. In the deeper part of very deep wells, the frac-gradient curve slope can nearly approach a vertical line. When this point is reached, the increase in fracture gradient with depth will be small, making deeper drilling very difficult. All this information is important in designing both the architecture and configuration of a well's casing program.

1.3 How to build the well architecture

The well architecture for a deep abnormally pressured vertical well (Figure 1-1) resembles an expanded telescope from the surface down with the largest outside diameter (OD) casing section at the top, followed by successively smaller OD casing sections inside, leading to the deepest and smallest diameter casing at total depth (TD). Each section of casing, starting at the top, isolates the interval of hole that it covers from circulating drilling fluid erosion. The casing also serves to isolate the lower integrity rocks placed behind pipe from the hydrostatic pressure that would be exerted by the typically higher density fluid needed to control higher formation pressures as the well depth increases.

The actual sizing (selecting of the outside and inside diameters of the pipe) of each casing string is done from the inside out, starting with the tubing. The tubing size is selected based on meeting the utility requirements for the well, such as desired producing rate, type of production (oil, gas or both) and operating pressures. Figure 1-2 shows a drawing of a typical deep, completed well with the production tubing running the length of the well from the surface to a depth just above the producing formation. The production tubing string provides the conduit through which the well will be perforated and produced.

A set of seals at the bottom end of the production tubing is stung into a packer or polished bore receptacle (PBR) set above the producing zone to provide pressure isolation between the tubing and casing annulus. The next casing out, or the casing where tubing is run within, is called the production casing. Its purpose is to provide well-pressure containment (back-up string) and a conduit within which a workover can be carried out in case of a tubing or completion failure. In sizing the production casing, the engineer should provide sufficient room between the tubing's connection OD and casing's ID to allow washover capability during a workover where the tubing has failed or become stuck. After the production casing is set, a clean, solids-free packer fluid should be circulated and placed in the casing all the way from bottom to the surface. The completion packer should then be installed inside the production casing, unless a polished bore receptacle (PBR) has been installed as part of the production casing string, at a desired depth above the producing zone. When the tubing is run to complete the well, it is landed in the packer or PBR, forming a seal between the anticipated producing flow stream inside the tubing and the production casing annulus, which is left with the light, clean, solids-free packer fluid above the packer or PBR. The setting depth of the production casing is always deeper than the tubing. It is always set across and below the producing zone to provide sufficient rathole (space between the packer and the bottom of the casing) for perforating and other production logging and producing operations.

1.4 Establishing casing setting depths required to drill to TD

Once the production tubing and casing are selected to meet the producing and other utility requirements for the well, they directly impact both the sizing of all outer strings needed to reach the final well depth and the hole size required to accommodate each casing string. After selecting the tubing and production casing, the next step is to select the casing and/or liner shoe depths that will be required to reach the production casing setting depth, starting from the surface. The actual sizing of each string of pipe will wait until after determining how many casing strings or liners will be required, and how deep each shoe will need to be set as the well is drilled down.

1.5 Conductor/conductors setting depth

In a typical land well the first casing string set at the surface is a conductor that can be cemented in a drilled hole or driven using a pile driver. The conductor serves three principle purposes:

- To prevent washout of the hole while drilling surface hole;
- To provide a means for diverting the drilling fluid being circulated down the drill string and returning up the annulus back to the rig circulating system for processing and return back down the well;
- To help, along with the surface casing, suspend the weight of the wellhead and subsequent tubing and casing strings that will be landed in the wellhead. For very heavy casing loads, more than one concentric conductor may need to be set and cemented inside for additional support. In some cases on land wells, load-bearing mats may be used where the outside conductor can be welded to it to provide some addition support. In an area where there is a possibility of encountering shallow gas while drilling the surface hole, the conductor should be outfitted with a diverter and be set deep enough to provide sufficient shoe integrity to allow diverting of flow a safe distance from the rig using a blooey line.

In offshore wells the first string set is often called the "structural casing." In shallow water depths, moderate but adequate soil strength is common just below the mudline, and the first string is usually driven with a pile driver. Where a hard seafloor exists the structural casing is cemented in a drilled hole. On deepwater wells, soil strength below the mud line is typically low, and the structural casing can be jetted using an internal retrievable downhole motor and bit extending under the casing. Once the desired depth is reached, the motor and bit assembly can then be disengaged from the structural casing and either pulled at this depth or used to drill additional hole to a deeper depth below the initial casing, where a second conductor can then be run and cemented. The depth for setting structural casing will usually depend on soil analysis information. On occasion, particularly when softer formations exist near the surface and when very heavy loads from the casing program are expected, it may be necessary to set more than one conductor. When this is required the procedure discussed above for drilling below the first structural casing string is used to drill the next section of hole to run and cement the concentric conductor back to the mudline. Where preset templates with slots for multiple wells are set on the ocean floor before drilling the wells, the templates are landed and set using piles at each corner that are jetted or drilled and cemented below the mudline to support and hold the structure in place. These templates serve only to help position and make flowline tie-in and control line connections, and to provide a means for accurate spacing of the well casings. The templates are not designed to help support the individual well loads which must be carried entirely by the structural casing and concentric conductors.

1.6 Designing well architecture for a complex well

Figure 1-3 shows formation pressure and fracture gradient curves vs depth for an example well that will be used for the remainder of this discussion. This example is for a land and/or a shallow water depth well (+/- 1,000 ft water depth, though this may vary) where fracture gradient build-up due to overburden begins in the shallow subsurface formations and builds steadily with depth. (In deepwater wells, formation fracture capacity builds very slowly below the sea floor and it can take 3 or 4 casing strings and/or liners just to drill to 6,000-8,000 ft below the mudline. This is because the

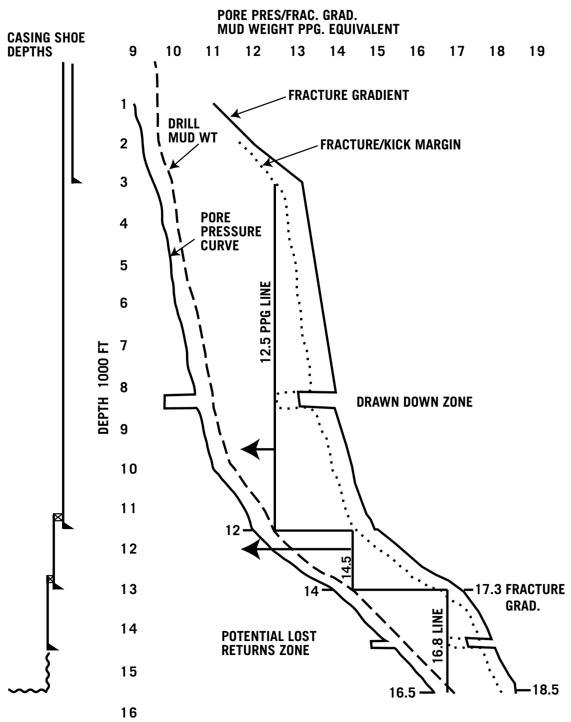


Figure 1-3: Pore pressure, fracture gradient, drill m.w., frac. gradient margin vs. depth for example well case and resulting casing shoe depths.

formation overburden from the rig to the mudline does not exist and is replaced by much lighter sea water, weighing about half of that of rock material, while the fluid in the riser exerts a full hydrostatic head of mud to the wellbore at a given depth all the way from the floating rig circulating system +/- 60 ft above sea level. Often the difference between pore pressure and fracture capacity in the shallow formations is no more than +/- 1 ppg. This results in having to set several casing strings in succession over short drilled intervals to avoid losses to the upper open formations as the mud weight is raised to control increasing pore pressure with deepening. As the well goes deeper and the effect of the formation overburden begins to help compaction and rock strength, the rate of fracture capacity build-up vs pore pressure increases, so that the amount of hole that can be drilled before having to set pipe can be lengthened. Even when this occurs, however, the difference between pore pressure and the fracture gradient of formations in deepwater wells will typically not exceed 2-2 ½ ppg.) The pore pressure and fracture gradient curves for the example well in Figure 1-3 are shown in equivalent pound per gallon mud weights. This example is intentionally complex to help demonstrate how important it is to leave options open to allow for contingencies if the wellbore conditions change from the expected or planned. (A simpler well example showing the process used for selecting the setting depths for casing shoes in a deep abnormal pressure well is presented in the Ted Byrom book entitled "Casing and Liners For Drilling and Completion," Gulf Drilling Series, Gulf Publishing Co. Refer to Chapter 3, paragraph 3.2.5.)

This example includes a drawn-down zone between 8,200 and 8,500 ft, as might be present when existing production in shallower horizons above the well's projected total depth has reduced formation pressures below the original gradient at that depth. Further, the example includes a potential lost returns zone below 14,200 ft and above 14,500 ft, which is just above the targeted production pay zone, starting at 14,700 ft, and the projected total well depth at 15,500 ft. These complexities have been added to the example case to help show how creative thinking can lead to options necessary to optimally and safely complete a well to its intended target.

1.6.1 Establishing a drilling mud weight schedule and fracture gradient safety factor

The annotated curves on Figure 1-3 show the:

- Well's predicted pore pressure;
- Mud weight for drilling the well (0.5 ppg over pore pressure);
- Predicted fracture gradient;
- Maximum drilling mud weight limit (fracture gradient safety margin) below fracture gradient vs depth that will be used for drilling each section of hole. The fracture gradient safety margin curve ranges from 0.5-0.7 ppg below frac gradient (dependent on regulations and/or knowledge of the area or section being drilled) to allow for handling a well kick, and to allow for surge pressures while tripping, and to account for equivalent circulating density (ECD) while drilling and circulating without fracturing the well. (Computer programs are available in industry for calculating surge and circulating pressures in a well system.)

The operational process used to determine when drilling should stop below each casing shoe is to drill ahead, raising the mud weight as dictated by the increasing pore pressure until the mud weight required is equal to the lowest fracture gradient safety margin allowed for the section of hole being drilled. The lowest fracture gradient margin normally, but not always, allowed occurs at the last open casing shoe above or a short distance below. When the mud weight required to drill deeper reaches this limit, drilling must stop and the section must be cased to protect it from higher hydrostatic pressure that would result from higher mud weights required to drill below this point.

1.6.2 Selecting the surface casing setting depth

Surface casing setting depth is determined by the following two drivers:

- Regulations primarily driven by rules to protect fresh water;
- The fracture gradient for the formations below the shoe, which must be high enough to allow drilling to the next casing point without losing mud, from the hydrostatic head of the mud weight required to drill to the desired depth. Sometimes hole problems from sloughing or swelling formations may force early setting of the surface casing which in turn will change the depth where the next casing will need to be set.

In the example here, planned setting depth for surface casing is 3,000 ft with 9.8-ppg mud in the hole. (Refer to Figure 1-3.) The anticipated fracture gradient at 3,000 ft is 13.2 ppg. Since the data shows that there is a drawn-down producing zone between 8,200 and 8,500 ft that is expected to break down at 13.2 ppg, there is no need to push the surface casing shoe deeper to gain more fracture gradient capability at the shoe. The drawn-down producing zone fracture gradient below 8,200 ft and the shoe fracture gradient at 3,000 ft will both limit how high the mud weight can be increased to push the intermediate hole as pore pressure increases with depth. The 3,000 ft surface casing setting depth also exceeds the fresh water protection regulatory requirement depth.

1.6.3 Drilling below surface casing to the protective casing setting depth

After running and cementing the surface casing at 3,000 ft and nippling up the BOPs, the plan is to drill out the shoe to test for cement integrity and to establish the formation fracture gradient below the shoe. If the test results are good, indicating that the shoe formation integrity is about 13.2 ppg, then drilling ahead can proceed while raising the mud weight as scheduled, based on pore pressure increasing with depth. The plan calls for carrying an 11-ppg mud weight when the hole is drilled across the drawn-down producing zone at 8,500 ft. But below this depth, the well will require increasing the mud weight as drilling proceeds into the transition zone. Depending on the quality of the available information on the fracture gradient for the drawn-down zone, it may be wise to test for hole integrity at this depth up to the mud weight that will be needed to drill and to run and cement casing at the projected setting depth of 11,500 ft. The expected fracture gradient at the drawn down zone is 13.2 ppg, and the fracture gradient safety margin drilling mud weight is 12.5 ppg. The test mud weight for the section should be equal to the required fracture gradient mud weight of 13.2 ppg to ensure that the drilling mud weight of 12.5 ppg will have a safety margin to handle a potential kick and to account for surge pressures and ECD while drilling. The procedure for doing this test would be to slowly raise the mud weight towards 13.2 ppg with the drill string sitting on bottom at the base of the drawn-down zone and to monitor for potential losses. If ECD for the system is 0.2 ppg, then the actual test mud weight of the circulating fluid would be 13 ppg, which, when combined with the ECD, would be equal to 13.2 ppg on bottom.

What are the possible results and consequences of running the weight-up test? If mud losses occur when weighting-up, the drill-ahead plan must be changed accordingly, and the intermediate casing must be set shallower than planned. If the weight-up test is good, then the well can drill ahead while letting the mud weight drift back a little towards the scheduled weight for this depth. As the well gets deeper, it is anticipated that the mud weight must be raised back to 12.5 ppg as the hole approaches a depth of 11,500 ft. Drilling must be stopped when the mud weight reaches 12.5 ppg, because the fracture gradient safety margin will have been reached at both the surface casing shoe and at the drawn down zone depths. As shown on Figure 1-3, the mud weight limit can be displayed graphically as a 12.5 ppg mud gradient vertical line extended upward from 11,500 ft towards the surface casing shoe at 3,000 ft. (Note that both the fracture gradient safety margin at the loss zone depth and at the surface casing shoe are aligned with the 12.5 ppg mud gradient line.)

A protective casing (intermediate) string will be set and cemented at this point from 11,500 ft to the surface and landed and sealed in the wellhead hanger to provide the burst rating capability needed to drill deeper. The lower pressure-rated surface casing will be covered and isolated by the intermediate protective casing, which is designed to handle the mud weights or a kick, should one occur, as drilling proceeds towards the higher geopressured sections of the well below this depth.

1.6.4 Drilling below protective casing towards the next casing point

After cementing the casing and testing the BOPs, the plan will be to drill out the shoe and test for cement integrity and formation leak-off, or fracture gradient capacity at this depth. If the test is good and the fracture gradient is 15 ppg equivalent are greater, as shown in Figure 1-3, drilling ahead can continue. If the leak-off is low, a squeeze is necessary. The fracture gradient safety margin limit at this shoe will be set at 14.5 ppg, a ½ ppg below the fracture gradient. Pressure in this section is expected to build gradually until the mud weight reaches 14.5 ppg at a depth of about 13,000 ft. At this point the mud weight required to control the formation pressures is equal to the fracture gradient safety margin limit at the last casing shoe and drilling must stop to set pipe before drilling ahead. The pipe selected is shown as a liner, which will serve as an extension of the protective casing above. The top of this first liner will overlap into the protective casing and be hung above the shoe from about 11,200 ft to the total hole section depth of 13,000 ft. The liner and casing above will both be designed for the mud weights and pressures expected below this point to drill and handle a kick, if necessary, all the way to TD.

This is an excellent application for use of an expandable hanger. There will be a detailed discussion later in Chapter 2 on well construction describing how and why the selection of a liner here is the appropriate choice (Refer to Chapter 2, Paragraph 2.3.3.) Chapter 2 will also clearly outline the procedures that should be used to conduct the cement job to ensure that the section can be safely and effectively isolated.

1.6.5 Drilling below the first protective liner and across the lost returns section-decision point

After setting and cementing the first protective liner in the hole, the plan calls for testing the liner top, weighting up to 15 ppg, and then drilling out and testing the liner shoe cement job, as well as determining the formation fracture gradient below the shoe. The expected fracture gradient for the shoe is 17.3 ppg at 13,000 ft. If the test is good, the plan is to drill ahead, increasing mud weight as needed to control increasing formation pore pressures. The fracture gradient safety margin at this shoe should be set at 16.8 ppg, which is 0.5 ppg below the formation integrity test results. When drilling reaches 14,500 ft, the mud weight is expected to be 16 ppg, which is still below the fracture gradient safety margin of 16.8 ppg at the shoe above at 13,000 ft. However, at this depth, the planning data indicates that the well has drilled through a section above where lower stress formations possibly incapable of withstanding the 16.8 ppg mud weight required to drill the target zone and reach TD may exist. (To contend with this possibility, a contingency liner should be added to the well plan.) Before drilling ahead and opening the pays, it is critical to know whether the lower stress zone is present, and whether it can safely sustain the mud weight required to drill and control pressure in the pay zone. The hole must also have enough pressure integrity to allow handling a kick situation, should one occur. Finally, the hole must also withstand surges while tripping, as well as running and cementing the production casing when the well is at TD. Failure to maintain well control because of downhole losses to weak formations after opening the pays could lead to an underground blowout and loss of the well, or worse.

The right plan at this point is to test the drilled section of hole for pressure integrity by slowly raising the mud weight, while taking the ECD into account, to an equivalent of 17.3 ppg before deciding to drill ahead. (If ECD is 0.2 ppg, then the mud weight should be raised to 17.1 ppg to result in a 17.3 ppg circulating open hole test.) If no losses are noted during the pressure integrity test, drilling can proceed to the projected TD while letting the mud weight drift back towards the schedule without having to set pipe at this point.

If, however, losses are noted during weight-up then the section will have to be cased above 14,500 ft before proceeding to drill through the pays and to TD. (The following four paragraphs will discuss the options that should be considered for selecting the type liner that should be set across the lower stress zone if isolation of the section is required at this point) In either resulting case from the integrity test, the final completion procedure for this well after reaching TD will be to set a liner to isolate the pay section on bottom. (The reason for choosing a liner for this example case vs running a full production casing string when reaching TD will be discussed in detail in Chapter 2 on well construction design.)

1.6.5.1 Lost returns zone test fails—2nd liner decision point—protective liner alternatives

As discussed above, if losses occur when the mud weight is raised short of reaching the ECD of 17.3 ppg during the hole integrity test at 14,500 ft, it will be necessary to set the extra contingency liner included in the well plan to case off this section of hole before opening the pay zones. (Including a contingency liner or casing string should always be part of a good plan on a complex well like this example.) The simple answer in most cases might be to set and cement another protective liner across the weak zone, shown in black and labeled as liner 2, set to a depth 14,500 ft, on Figure 1-4a. Liner 2 would be hung from inside and below the first protective liner 1 that was set at 13,000 ft before drilling to this point. After setting liner 2, the next step would be to drill the production section to 15,500 ft and then to set a final production liner across the interval to bottom, shown in red, on Figure 1-4a. To complete the production casing a tieback string would then be run from the top of the final production liner to the surface. (The tieback for this case is shown in dashed red on Figure 1-4a). While this is a viable plan, other design options may hold greater advantages.

1.6.5.2 Combination protective/production liner alternative

A different design option could be to set a higher pressure rating combination protective/production liner across the weak zone, which would first serve as a protective liner to allow drilling to TD; and later be used as part of the production casing for the well. After hanging and setting the combination liner 2 below the first liner from 12,700 ft to 14,500 ft across the weak zone (shown in solid red on Figure 1-4b), the production hole can then be drilled to TD projected at 15,500 ft. After drilling the pay section a final production liner, also shown in red, can be set below the combination protective/production liner from 14,200 ft to 15,500 ft, to complete the bottom section of the production casing. The

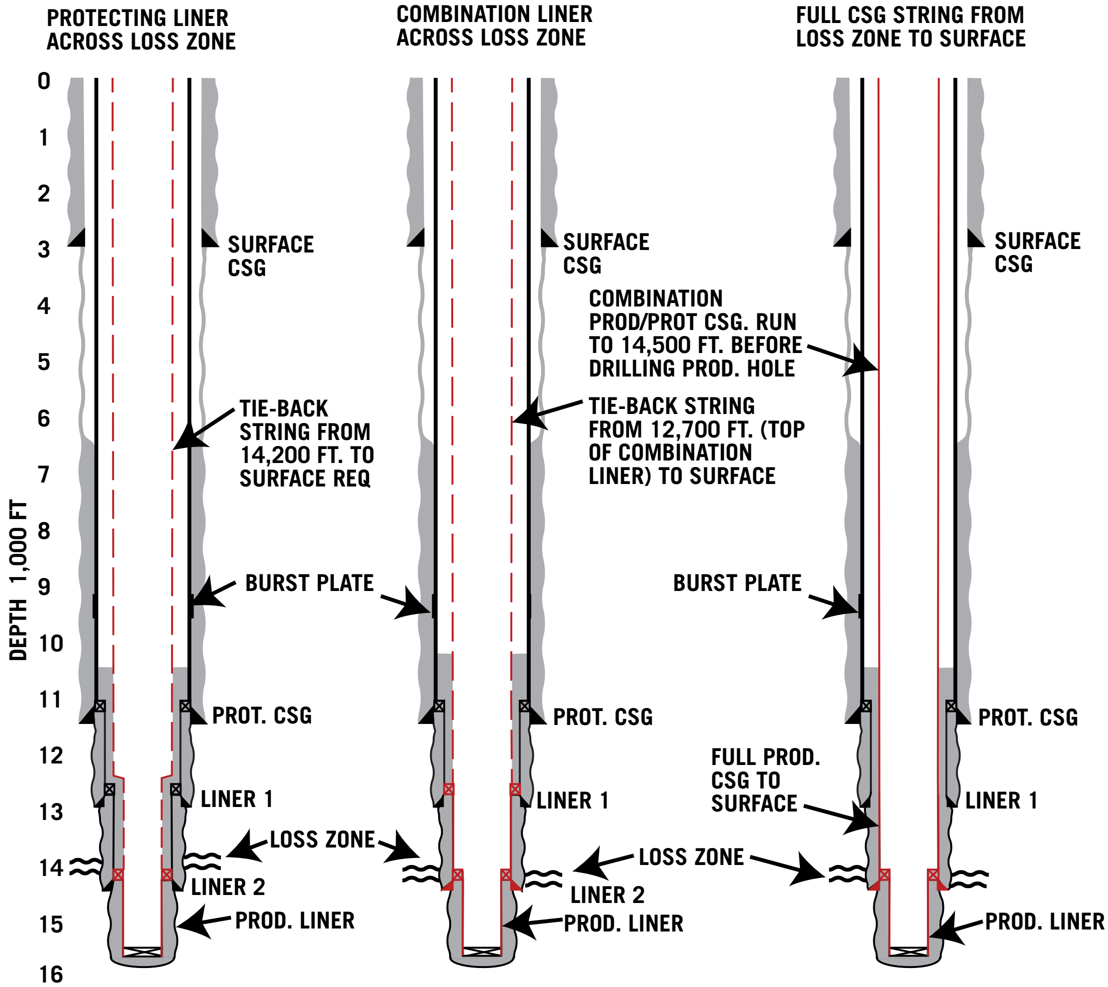


FIGURE 1-4a

- PROT. LINER 1 AT 13,000 FT
- PROT. LINER 2 AT 14,500 FT
- PROD. LINER AT 15,500 FT
- TIE BACK FROM TOP PROD. LINER AT 14,200 FT
- PROD. CSG I.D. REDUCED BELOW 12,700 FT
- SMALL D.P. REQ BELOW 12,700 FT TO DRILL PROD. HOLE

FIGURE 1-4b

- PROT. LINER 1 AT 13,000 FT
- COMBINATION LINER 2 AT 14,500 FT
- PROD. LINER AT 15,500 FT
- TIE BACK FROM TOP COMBINATION LINER AT 12,700 FT
- PROD. CSG I.D. REDUCED BELOW 14,200 FT
- SMALL D.P. REQ BELOW 12,700 FT TO DRILL PROD. HOLE

FIGURE 1-4c

- PROT. LINER 1 AT 13,000 FT
- FULL STRING COMBINATION CSG FROM 14,500 FT TO SURFACE
- PROD. LINER BELOW 14,500-15,500 FT ELIMINATES TIE BACK
- PROD. CSG I.D. REDUCED BELOW 14,200 FT
- TOTAL DRILL PIPE STRING REQ REPLACEMENT FROM SURF TO DRILL PRODUCTION HOLE

Figure 1-4 (a-c): Example well casing configuration options lost returns case at 14,500 ft.

upper part of the production casing string would then be set as a production casing tieback from the top of combination liner 2 from 12,700 ft to the surface (shown in dashed red on Figure 1-4b). This design would allow running the tieback from the top of the bigger ID combination liner 2 instead of from the top of the deeper final and smaller OD production liner at 14,200 ft, as was discussed on paragraph 1.6.5.1 above and shown on Figure 1-4a. Running the tieback from the top of combination liner 2 would save 1,500 ft of extra production casing since it results in using the combination service liner between 14,200 ft and 12,700 ft in both protective and production service. This choice would also result in a greater ID in the production casing string all the way to the top of the final production liner at 14,200 ft that will be set across the pays to finish the well.

1.6.5.3 Full casing string to the surface vs. Liner alternative
One other option to consider at the 14,500-ft depth, after determining that the loss returns zone would have to be isolated behind pipe before drilling through the pays, is to set a full string of casing from 14,500 ft to the surface instead of setting just a liner across the loss zone. The string would be designed both as a protective casing string (shown in solid

red on Figure 1-4c) for drilling to TD and then used as the production string to the surface after the final production liner would be hung below it from 14,200 ft to 15,500 ft through the pay zones and to TD. After setting the full string at 14,500 ft, only a short interval remains to be drilled to TD the well. By using drillpipe with casing-friendly, hardbanded tool joints there would only be a very low risk of wear on the casing that would later be used in production service. (A program for wear management, prediction, and monitoring should be implemented to ensure that wear will not be a factor in decreasing the pressure containment capability of critical casing strings in a well.) This completion option to set a combination protective/production casing from 14,500 ft to the surface before drilling the pay zone and setting a final production liner across the pays would eliminate the need for a production tieback to be installed to complete the well. This option would result in considerable savings, while simplifying completion operations and ensuring the best possible cement job across the pays by setting a short rotating liner on bottom to finish the well.

Setting a full string of a combination protective/production casing to the surface from 14,500 ft (Figure 1-4c) at this stage of the well would, however, result in placing the existing protective casing string used to drill the well to this depth behind the new smaller diameter casing. The new reduced ID casing would then have to be employed to house the drillstring that would be used to drill the well to TD. The smaller diameter of the new casing will force having to change-out the entire drillstring of large diameter drillpipe used to drill the well to this depth to a smaller diameter drillstring. This swap to smaller drillpipe would be necessary in order to provide sufficient clearance between the drillstring and the smaller casing to allow drilling, circulating and conducting all of the required operations to complete the well.

Drilling to this depth has been done through a protective string, made up of the large-ID protective casing from the surface to 11,500 ft and of the large-ID first liner 1 hung and set inside the protective casing from 11,200 ft to 13,000 ft. By setting liner 2, here at 14,500 ft with the top hung at 12,700 ft inside liner 1, in either case shown in Figure 1-4a or Figure 1-4b, drilling the final section of hole to TD would still be done with the same drillpipe running inside of the bigger existing protective casing string above the top of liner 2. After setting the second liner 2 it would only be necessary to downsize the drillstring below 12,700 ft to drill the final hole section of the well from 14,500 ft to TD.

After a full analysis of the options it was determined that the higher circulating pressures and costs for changing to the smaller drillstring and related tools for the "full casing string to the surface vs. liner alternative" would not result in either an economic or operationally viable option.

Under a less complex case with lower mud weights and less casing strings and where the last interval to be drilled is short, the option discussed above can be of great advantage both cost wise and operationally and should be evaluated.

1.6.5.4 Evaluating the options for casing off the loss zone
After evaluating the three options considered above it can be concluded that the least cost and risk option is to select the combination protective/production liner to case-off the loss zone (Figure 1-4b). After setting this liner, drilling out, and testing the shoe, drilling would proceed through the pay zones to TD where the final production liner would be set. The final production liner in this well should be set using a conventional rotating liner hanger. (The topic on how to make the choice between using the different types of liner hangers or a casing string will be fully developed in Chapter 2 on well construction design.) After setting the production liner on bottom a production casing tieback would be run to complete the upper portion of the production casing string in this example well. The tieback would be run from the top of the combination liner tieback receptacle at 12,700 ft. The cement job for the tieback would leave the top of the cement partway back up into the protective casing (as shown) and the casing would be landed with its full buoyed weight. (See Chapter 10 on load and stability analysis for calculation required to determine the ideal cement height and to determine appropriate hanging weight to prevent buckling or joint failure due to load changes over the life of the well) Cementing the completion tieback inside the protective casing will result in leaving a closed annulus between the strings. In order to avoid the possible collapse of the production casing, or the burst of the protective casing from fluid expansion due to heating when the well is put on production, it will be necessary to install a surface pressure relief system, or a burst plate on the protective casing, as shown on Figure 1-4.

1.6.6 Food for thought- example to consider for the application of a long string vs liner alternative

Although the option to run a combination protective/production long string above 14,500 ft instead of a liner to avoid the need to run a tieback production string later was not the best option in the example being used in this case, there are some good applications for this approach. An excellent example for the application of this approach of setting the production casing in a well before the production interval is drilled, is in horizontal wells that are being completed in tight oil and gas zones where multiple fracture treatments are used to break-up the rock and connect the trapped hydrocarbons to get the wells to produce. There are several advantages to setting a full string of a combination protective /production casing before drilling the horizontal hole through the pays, and then setting and cementing a liner below the casing through the interval that will be fractured, instead of setting a full production casing string to the surface at the end of the well. Setting and cementing casing atop the pays before drilling through them allows for a better cement job above the production casing shoe, which can be very important and has a unique advantage. The cement job above the combination-casing shoe will serve as a tested independent barrier to any pressure resulting from hydraulic fracturing operations being conducted in the liner below. The best cement job on any casing string, all other procedures being equal, is always going to be around the shoe because that part of the casing string gets the most sweep from the spacer and cement pumped during the job. Additionally, the last cement pumped during a job will also be the least contaminated cement left in the well after the pumping stops. The casing set before penetrating the pay section can be cemented using best practices, then drilled out and tested to leak-off prior to drilling the production zone. If the shoe fails it can be repaired. If perforating and squeezing is ultimately required to do a cement job repair, it is of no consequence because the bottom joints of the production casing will be lapped by the production liner that will be hung from inside the casing shoe and through the pays when the well is completed. (This combination protective/production casing shoe cement job serves as a tested independent barrier to future hydraulic fracturing operation pressures from below, while also eliminating a potential open annular path to the surface casing shoe.)

After setting the combination casing string and drilling the horizontal productive interval a rotating liner can be run and cemented through the pays and the liner top can be tested both ways. Solid body roller imbedded type centralizers installed on the liner can be used very effectively to allow rotation of the liner. These devices eliminate casing drag on the low side of the hole and result in manageable torque before and during the cementing operations. A liner top packer can also be run atop the hanger and set after cementing to provide a secondary barrier if needed. When the well is hydraulically fractured, if the cement job in the pay zone should fail towards the top, the likely path would be to a zone in the production interval below the previously tested combination protective/production casing shoe.

1.6.6.1 More food for thought

Any completion design that involves using a long string to the surface instead of a casing and liner procedure as discussed above will always wind up with the most contaminated cement in the annulus in the upper part of the cement column. Conversely, as discussed above, the least contamination cement will be in the lower part of the column towards the end of the casing shoe. This will be the case even when using all of the best practices. If the casing is to be used to conduct a fracturing procedure the most contaminated cement still winds up at the top of the cement column above the intended fracture zone and the least contaminated cement will be toward the shoe. A full-length conventional production string set across the pays that is cemented and then landed at the surface has no viable way to conduct an active integrity pressure test of the cement job in the annulus prior to pumping the fracture treatment. If the cement job should fail the path would be up the annulus leading to the surface casing shoe.

1.7 Selecting the casing sizes to be set at each casing point in the example well

As noted at the beginning of this chapter, well architecture is developed from the inside out. After establishing the depths where pipe will have to be set in order to allow drilling the well down while protecting shallower upper sections from pressures due to the higher mud weights required to drill deeper, the next step is to select the pipe sizes and corresponding required hole sizes for each hole section. (Refer to Figure 1-5) The innermost string in the well (production tubing), which is run and installed inside the production casing, determines the size of the production casing. The production casing size then establishes the size of the next outer casing for drilling the size hole required to provide the space and clearance for the inner casing to be run in and cemented. This process of selecting the subsequent outer casing sizes for each sting that needs to be run in a well is repeated until the size of the starting hole and casing when the well spuds is determined.

There are no formulas for determining the ideal borehole size in which to run a given size casing. The hole must be large enough for the casing to pass freely and with enough space to allow circulation and cementing without breaking the well down. In the example used here clearances between casing and hole sizes have been selected by using charts for hard rock formations provided in the previously cited Ted Byrom book entitled “Casing and Liners for Drilling and Completions” as tempered with experience from drilling and completing many deep, high-pressured wells. Experience in a given area will serve as a good guide for making the choices. Bigger hole sizes relative to casing OD provide the best opportunity to get a good cement job; but bigger hole sizes cost more to drill. By considering all aspects of performing a cement job, it is possible to accomplish the job with clearances of 1-1 ½-in. (hole ID minus casing OD) in stable, hard rock formations where short, flush joint liners are run and a safe margin between fracture gradient and circulating fluid density exists. In cases where hole dogleg severity can increase the difficulty of getting casing in the hole, it might be necessary to provide greater clearances between the casing OD and the hole. Reaming-while-drilling tools and bi-center bits can be used to drill a bigger hole out from under casing than the drift will allow using standard bits if desired or necessary to provide greater clearances.

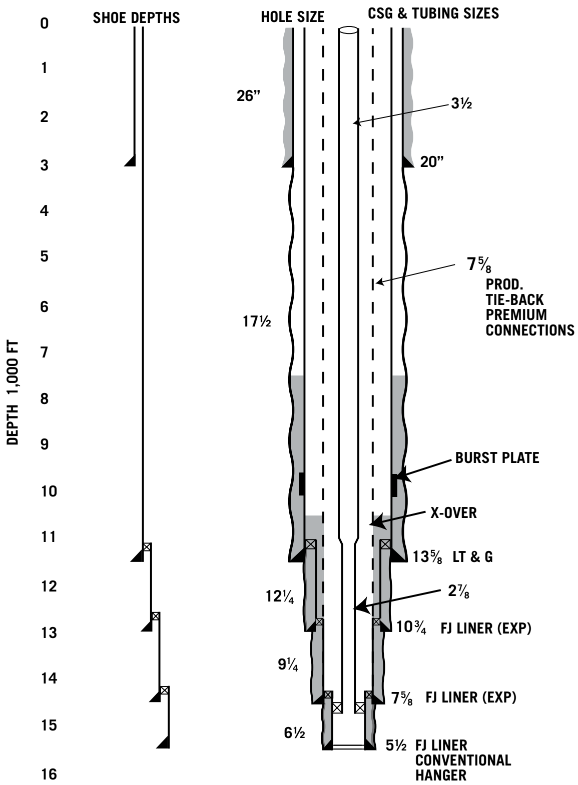


Figure 1.5: Tubing, casing & hole sizes at each casing point in example well (conventional design).

1.8 Tubing and casing design procedures

(Refer to Figure 1-5 in the discussion on drilling hole size selection and sizing and design of all casing strings for the example well.) The size required for the production tubing is generally determined by production engineers and is based on anticipated production fluid type and rates, as well as other well utility operational requirements. (The assumptions for the example used here is for sweet service. If sour service and/or very cold temperature operations were expected, special requirements, including hardness and minimum yield restrictions and materials testing, will be required to certify the acceptability of selected materials for the intended service.) The production casing serves as the back-up string to contain well pressure if a tubing failure should occur after the well is put on production. (The design procedures and curves for each string in the example well for this discussion are presented in Appendices 1A, 1B, and 1C.) The applicable design parameters and load curves are based on well pressure conditions driven by pore pressure and fracture gradient curves using a modified version of the criteria outlined in the Ted Byrom book referenced previously. Casing and tubing performance property data is available from many industry sources. For convenience the values used in this design discussion have been obtained on line from Hydril's website (now listed as TenarisHydril). (Performance properties are based on API standards for minimum yield requirements for selected weights and grades. Safety factors used in these examples were selected from a range of those used by several operators. Selection of safety factors is generally driven by the degree of certainty as relates to the available data and experience of the operator in the area being drilled.)

1.8.1 Production tubing design

In the well case example being used here it will be assumed that based on production type (sweet service) and expected rates and pressures, the production engineers have determined that the production tubing string required for this well should be a combination string of 2 ⅞-in. OD tubing at the bottom and 3 ½-in. OD from the surface to at least a depth of 11,000 ft. The anticipated maximum shut-in pressure for the well is given as 11,440 psi. (This is a 16.5-ppg equivalent bottomhole pressure minus a gas gradient to the surface.) The expected pump-in, kill and stimulation pressure requirements will not exceed 13,000 psi at the surface. (Refer to Appendix 1A for production tubing and casing burst design criteria, design curves and materials selection based on the design parameters above.) Based on the pressure requirements given above and using the criteria presented in Appendix 1A the tubing design selection is as follows: The top section from the surface down to 11,000 ft is 3 ½-in., 12.7-lb C-95 tubing with PH-6 (4.3-in. OD) connections with a rating of 13,570 psi burst with a 1.312 safety factor. The tubing from 11,000 ft to the packer at 14,500 ft is 2 ⅞-in. 8.7-lb C-95 tubing with PH-6 (3.5-in. OD) connections with a rating of 13,570 psi burst with a 1.312 safety factor.

1.8.2 Production casing design—liner required through the loss zone before drilling the pays

In the worst case scenario assumption when drilling the lower part of the well, the loss zone above 14,500 ft is not capable of carrying the mud weight required to drill to TD. If this occurs it will be necessary to run another liner (this is a contingency liner 2 that has been added to the well plan) below the first protective liner 1 that was set at 13,000 ft. The liner 2 that will be set across the loss zone down to 14,500 ft will need to be hung from inside the first liner 1 above from about 12,700 ft. (Refer to Figure 1-4b.) In the earlier evaluation of options considered for isolating the loss zone above 14,500 ft (paragraph 1.6.5.4), setting a combination protection/production liner 2 was selected as the best option for casing-off the weak zone before drilling out and through the pay zone to TD at 15,500 ft. A final production liner would then be set from the lower section of the combination liner to complete the lower portion of the production casing string. A tieback run from the top of the combination protective/production liner 2 at 12,700 ft would then complete the top portion of the production casing string.

Refer to Figure 1-5, as discussed above in paragraph 1.7. Charts available in "Casing and Liners for Drilling and Completions" by Byrom are used as a reference guide to determine the size of drilled hole needed to accommodate the selected casing sizes for this example well. The chart is Figure 3-10 on page 98, entitled "Typical bit/hole and casing sizes for hard rock formations." As discussed in the paragraph above, the bottom section of production tubing that will be run and set in a packer inside the lowest most production liner is 2 ⅞ in. with PH-6 connections with an OD of 3.5 in. This tubing design establishes that the bottom production liner must be no smaller than 5 ½- in. OD (4.6-in. ID) flush joint casing to accommodate the 2 ⅞-in. tubing. This 5 ½-in. flush joint production liner will require a minimum drilled hole size of 6 ½-in. in order to be safely run and cemented. To meet this minimum hole size requirement in the final production hole will require that the combination protective/production liner set above at 14,500 ft be at least 7 ⅝ in. and no heavier than 39 lb to allow the drift ID needed to drill the 6 ½-in. hole. The tubing at the top of the well will be 3 ½ in. with PH-6 connections with an OD of 4.3 in. (Refer to Appendix 1A for burst design curves and weights and grades selected to meet the design parameters for the production casing.) The production casing required at the top of the well to accommodate the tubing connection OD should be 7 ⅝ in. (6 in. to 6.5-in. ID). Because the maximum load and burst pressure requirements for the production casing occur at the top of the well under a worst case scenario of a tubing failure and full shut-in pressure on the casing, the minimum production casing weight and grade with sufficient ID to accommodate the tubing connections required to meet the pressure and load design at the top and down to 12,700 ft is 7 ⅝-in., 45.3-lb Q-125 (drift ID 6.31 in.). Below this depth, the combination liner hung at 12,700 ft down to the shoe at 14,500 ft, can be reduced to 7 ⅝-in., 39-lb P-110 (drift ID 6.5-in.) and still meet the pressure requirements. (Because the pressure requirements for the combination service protective/production liner are higher in production operations than in protective liner operations when drilling the last section of hole, the production design will dictate the weight and grade for this liner.) Because the connections for the production casing from the surface to the liner top will be in oil and gas pressure backup containment service, they will need to be premium grade with an OD of 8.3 in. or less. (Connections in the uncemented portion of the casing should also be certified to be used is collapse pressure service.) The combination protective/production liner from 12,700 ft to 14,500 ft should be 7 ⅝-in., P-110 flush joint casing to help reduce liner running surge pressures and the size hole that should be drilled to run the string in should be at least 8 ⅝ in. in diameter. The selected 7 ⅝–in., 39-lb P-110 liner meets the required internal drift ID of 6.5 in. to drill the production interval to accommodate the 5 ½-in. final production liner.

1.8.3 Protective casing design- selecting the liner and casing strings above the combination 7 ⅝–in. Liner

The next step is to size the outer liner and casing that will be set above 13,000 ft. (Refer Figure 1-5.) The liner must have sufficient ID to allow drilling the hole size required to accommodate running, hanging and cementing the combination 7 ⅝-in. 39-lb P-110 flush joint liner 2 designed and selected in the last paragraph. The hole size needed to run the combination liner below 13,000 ft could be as low as 8 ⅝-in.; however, since the hole section could encounter a loss zone, an extra hole size to facilitate cementing the almost 2,000-ft liner without losses would be ideal. With this in mind, a good choice that would provide at least a 9 ¼-in. drift to drill and run the 7 ⅝-in. liner through would be 10 ¾-in., 65.7-lb (9.4-in. drift ID) casing with FJ connections. This 10 ¾-in. FJ pipe will serve as the first liner 1 set under the protective casing set at 11,500 ft. This means that the 10 ¾-in. liner will be set inside the protective casing from about 11,200 ft to a depth of 13,000 ft. The drilled hole size necessary to accommodate the 10 ¾-in. FJ liner will require that the protective casing set at 11,500 ft have at least a 12 ¼-in. drift ID. This corresponds to 13 ⅝-in. casing that is no heavier than 88.2-lb/ft. The well protective casing architecture design will them be comprised of the 13 ⅝-in. casing at the top with the 10 ¾-in. liner 1 and the 7 ⅝-in. combination liner 2 below. This combination of casing and liners will compose the protective casing string for drilling the well through the pay zones and on to TD.

1.8.3.1 Continuous protective string design

Because the protective casing and liners will act as one continuous string to contain the pressures and mud density for drilling the well safely to completion, the protective string design should be done as for a single continuous tapered string. In the well example case used here formation pressures and fracture gradients increase with depth. This means that each time a deeper extension liner is set it automatically results in a higher pressure containment requirement for the entire string. The higher burst capacity requirement is caused both because of the increased mud weight required to drill the deeper higher pressured formations, and because the fracture gradient of the deeper set liner shoes raises the leak-off (relief) pressure at which a shut-in well kick will occur. When the increasing design pressure reaches a high level it is possible that casing with sufficient burst capacity to meet the design loads may not be manufactured in the larger upper string sizes as the hole is drilled deeper below extension liners. The only way to find out is to do the continuous string design and then search the API and/or manufacturer's performance properties tables in an attempt to find pipe with the materials and weight needed to do the job.

Appendices 1A, 1B & 1C present the design criteria and procedures required to select each of the casing strings for the example well. The criteria used for the protective casing and liners design (Appendix 1B, Conventional Protective Casing and Liners Design) is based on a modified approach to one described in the Gulf Drilling Series book titled "Casing and Liners for Drilling and Completions" by Ted G. Byrom.

One of the procedures discussed in the Byrom book that is used by some operators for protective casing design begins by limiting the design burst pressure at the surface based on the rating of preselected or available BOPs and wellhead equipment to be used to drill the well. With this as the limiting factor, the casing design and the casing setting depth is then selected with the objective of preferentially causing a failure of the formation at the casing shoe in the event of a massive kick instead of a failure of the casing, BOPs or the surface equipment. This procedure will usually work for less complex wells but will limit the ability to drill a well as complex as the example being used here. The modified version chosen for the example in this book is to set the protective casing and successive liners as deep as allowed by the fracture gradient of the open formations in each section being drilled, and then to design the casing, the BOPs, and the wellhead equipment with sufficient burst capacity to withstand the burst loads from a design kick scenario to preferentially force a failure at the deepest exposed casing shoe. If this is not possible because casing, BOPs or surface equipment are not available to meet the pressure requirements, then consideration would be given to installing a burst plate or weak joint deep in the casing string that would serve as a preferential pressure relief deep in the well. (The selection of the criteria for protective casing design for this book is based on the author's past practices and experience.) Alternatively, a different casing architecture configuration may also be considered and will be discussed later in this chapter.

1.8.3.2 Determining burst pressure profile from a kick scenario

The procedure being used in this book for determining the internal loads (pressures) that the protective string will have to withstand under a massive kick scenario provides the designer with the means for conducting a circulating kick pressure profile calculation using ideal gas law equations. (See Appendix 1B, Conventional Protective Casing and Liners Burst Design.) The well kick design scenario allows the design engineer to select the size kick (influx volume and magnitude of mud weight underbalance) that will occur and then assumes that the well is shut-in. The gas then rises (migrates) upward, or is brought to the surface by circulating, bringing high pressure up the well. As the high pressure gas comes to the top it causes the pressure in the shut-in well to increase until eventually it results in the weakest open zone to fracture, allowing the gas bubble to expand and fill some portion of the top part of the well to the surface. Once the pressure profile is established for the selected kick scenario, as the gas comes to the surface and the shoe ruptures, the protective string and surface equipment are then designed to withstand the resulting loads. The net burst design loads exerted on the casing and surface equipment are determined by taking the difference between the internal kick pressure profile and the casing external back-up pressure gradient; so that in the extreme case, relief of pressure occurs when the weakest open formation in the well will preferentially fracture over failure of any of the hardware.

1.8.3.3 Selecting the kick design criteria

The severity of the design criteria selected for protective casing will vary between operators. Some may choose criteria where the well is full of gas after taking a kick and fracturing the hole with no mud left in the well. Other operators will select a maximum size kick to be used as the worst case for designing the containment casing. This will vary based on experience in the area or other risk assessment alternatives.

In many jurisdictions, the design scenario selected by the operator must be approved by appropriate regulatory agencies. For the US Outer Continental Shelf (OCS), for instance, the Bureau of Safety and Environmental Enforcement (BSEE) must approve the permit to drill. BSEE allows the operator to select the worst case scenario and to submit the design without strict specific guidelines, other than that the scenario must be severe and based on data for the expected well pressures and complexity. Cases submitted must be defended or changed if a permit is not granted as originally submitted. In this well plan, the operator must submit a well design case that presents a worst case well control scenario as selected by the operator for approval. No special guidance on case severity is proposed by BSEE prior to submittal; however it must be consistent with expected well complexity and conditions in the area. Cases submitted must be defended or changed if a permit is not granted as originally submitted.

The example used here assumes a kick scenario when drilling through the pay section where the drilling mud weight is ½ ppg underbalanced and the protective casing string winds up half full of gas at the top when the shoe ruptures and the gas reaches the surface. (Ref Appendix 1B Conventional Protective Casing and Liners Burst Design.) The fracture gradient at the deepest shoe and the mud weight while drilling the pay section is based on the data presented in the example well design case curves (Figure 1-3). The internal pressure profile data curves can be calculated for the case when the gas first enters the well on bottom and for any other depths, as the gas moves towards the top, as the designer may choose. In reality, for a massive kick such as this example assumes, doing the calculations to establish the pressure profile data with the gas at the surface, and on bottom when it first entered the protective casing shoe, define the maximum pressure conditions over the entire length of the casing string. The results of the pressure profile calculation while circulating the kick are shown on Appendix 1B, Figure 1B-1. After establishing the maximum internal pressure profile curve the designer can then plot a curve for external pressure (backup) support vs depth for the well. The design (or differential) pressure can then be calculated by taking the difference between the internal and external pressures at different well depths. The net burst pressures vs depth are than plotted to establish the burst pressure for which the casing should be designed.

As shown in Appendix 1B (Figure 1B-2), the differential pressure curves that result from the assumed kick scenario in this example are greater than can be met by most of the 13 ⅝-in. segment of the protective casing string even when using the highest standard weight and grade pipe being manufactured (13 ⅝-in., 88.2-lb Q125). The drawn down producing formation beginning just below 8,200 ft and the assumed light annular fluid behind the protective casing, caused by settlement of mud solids over time, result in very high differential pressures in the middle and upper part of the hole, where it is the least desired under the assumed kick scenario. An attempt to remedy this problem by hanging the 10 ¾-in. liner higher up inside the 13 ⅝-in. casing to cover-up and eliminate exposure of more of the 13 ⅝-in. casing from the high pressure were not practical or economical versus changing the design. Essentially hanging the 10 ¾-in. liner higher inside the 13 ⅝-in. casing would move the highest kick pressure profile part of the curve further up the hole and ultimately result in placing one protective casing string inside another.

1.9 Alternative approach to address the deficiency in the protective casing design

The high casing internal pressure which results from the massive gas kick design criteria selected for the example case is basically caused by the high fracture gradient relief capacity (18 ppg) of the deepest shoe at the end of the protective casing string (7 ⅝-in.) at 14,500 ft. One possible solution could be to have a special mill run to manufacture a higher weight (thicker wall) of 13 ⅝-in. casing to meet the high burst pressure requirements. This choice would give up casing ID and reduce the drilling hole size that can be drilled below. Another consideration would be to increase the OD of the casing to 14 in., to increase the wall thickness to get more burst capacity, while retaining the ID. Another solution could be to provide pressure relief deep in the well by installing a weak joint or burst plate in one of the lower sections of the string. This would force a burst failure, at the burst plate, deep in the well in the worst case scenario instead of in the weaker 13 ⅝-in. upper section. A change in the size of the kick criteria could also result in lower burst pressure requirements which would be within the capacity of the highest rated 13 ⅝-in. casing that is manufactured. Yet another possible option would be to reduce the size of the production tubing for the well which would lead to a smaller overall OD casing design for the entire well which would have higher pressure ratings. Before considering these options however, it is far more interesting for learning and "thinking" purposes to seek a more creative and unconventional approach to solve the problem.

1.10 Unconventional architecture for protective casing design

(Refer to Figure 1-6 Unconventional Architecture design comparison to Conventional design.) One possible approach would be to prematurely set 13 ⅝-in. casing, as a liner down to 9,000 ft, to be hung from inside the surface casing set at 3,000 ft. The liner would be set across the shallow drawn down producing zone below 8,200 ft to about 9,000 ft, before reaching the fracture margin safety limit at the surface casing shoe above. (Using 16-in. pipe for surface casing pipe will easily accommodate the 13 ⅝-in. flush joint liner.) Setting this liner would isolate the weaker fracture gradient at the surface casing shoe and the drawn down formations above 9,000 ft, and result in increasing the fracture capacity of the open hole section, that would then be exposed to the mud weights required to drill to the next casing setting depth. The resultant objective of this approach is to use the higher fracture gradient at the liner shoe to push the next protective casing setting depth deeper than what would be possible by drilling from under surface casing in the conventional design case. Setting the protective casing deeper into higher pore pressure would result in a higher fracture gradient at the protective casing shoe with the objective of eliminating the need for one of the deeper liners to reach TD. The net effect of eliminating one of the deeper liners is that the protective casing selected at this deeper depth can have a smaller diameter, than in the conventional case, and therefore have a higher burst capacity, while allowing for the final production casing string to finish the well to be the same size as in the conventional case. The only way to evaluate this option objectively is to look at the design in detail beginning from the time when the 13 ⅝-in. liner is set from under the surface casing to 9,000 ft and ending when the well has reached TD. (Refer to Figure 1-6.)

The expected fracture gradient at the 13 ⅝-in. liner shoe at 9,000 ft is about 14.2 ppg with a fracture gradient safety margin mud weight of 13.7 ppg. The 16-in. surface casing and 13 ⅝-in. flush joint liner would then serve as a protective string to allow drilling to about 12,500 ft with a mud weight of 13.7 ppg, matching the expected fracture gradient safety margin at the 13 ⅝-in. liner shoe at 9,000 ft. This design would allow the long protective casing string to be set 1,000 ft deeper into the abnormal pressure transition zone than in the conventional case. (See vertical 13.7 ppg mud weight line extended from 12,500 ft to the 13.7 ppg fracture gradient safety margin line at the 9,000 ft shoe.)

The surface casing and liner combination used as protective casing to drill to 12,500 ft must meet the same gas kick design scenario criteria as for the original conventional case where the top half of the protective casing string would be full of gas, except that the fracture gradient limit and mud weight would be based on those matching the shallower setting of the 13 ⅝-in. liner and the mud weights for the section being drilled. (SEE Appendix 1C for burst design criteria, differential pressure curves, and material selections for this unconventional alternate architecture scenario.) Figure 1C-1 in Appendix 1C present the results of the kick profile calculations for the influx scenario assumed for drilling to 12,500 ft. Figure 1C-2 presents the differential pressure design curves for the kick scenario and the material selections for the casing required to meet the design. The surface casing design would be 16-in. buttress 84-lb P110 (14.85-in. drift ID) with a burst capacity of 4,515 psi with a 10% derating for wear and a 1.2 safety factor for any data variance. The 13 ⅝-in. flush joint liner would be 88.2-lb C-95 (12.25-in. drift ID) with a burst rating of 5,722 psi with the same safety factors. Both of the casings exceed the maximum differential pressure of less than 4,000 psi under the kick scenario assumed.

After drilling to 12,500 ft, a full casing string of 10 ¾-in. casing would be run to serve as a protective string to drill ahead while isolating the surface casing and 13 ⅝-in. liner from the mud weights and pressure requirements for drilling the deeper higher pressure formations. The earlier conventional design, where the 13 ⅝-in. long casing string was used as the protective string landed at the wellhead, would have required buttress connections with 14 ⅜-in. OD to carry the high casing weight. This in turn would have then required either 18 ⅝-in. or 20-in. surface casing to provide sufficient ID to accommodate the 14 ⅜-in. OD connections. The alternate unconventional design configuration using 16-in. casing with a 13 ⅝-in. flush joint liner below, and then a 10 ¾-in. longstring, will therefore also help reduce the size of the surface and intermediate holes that are required to drill down to the 12,500-ft range. (See side by side comparison of conventional and unconventional designs on Figure 1-6.)

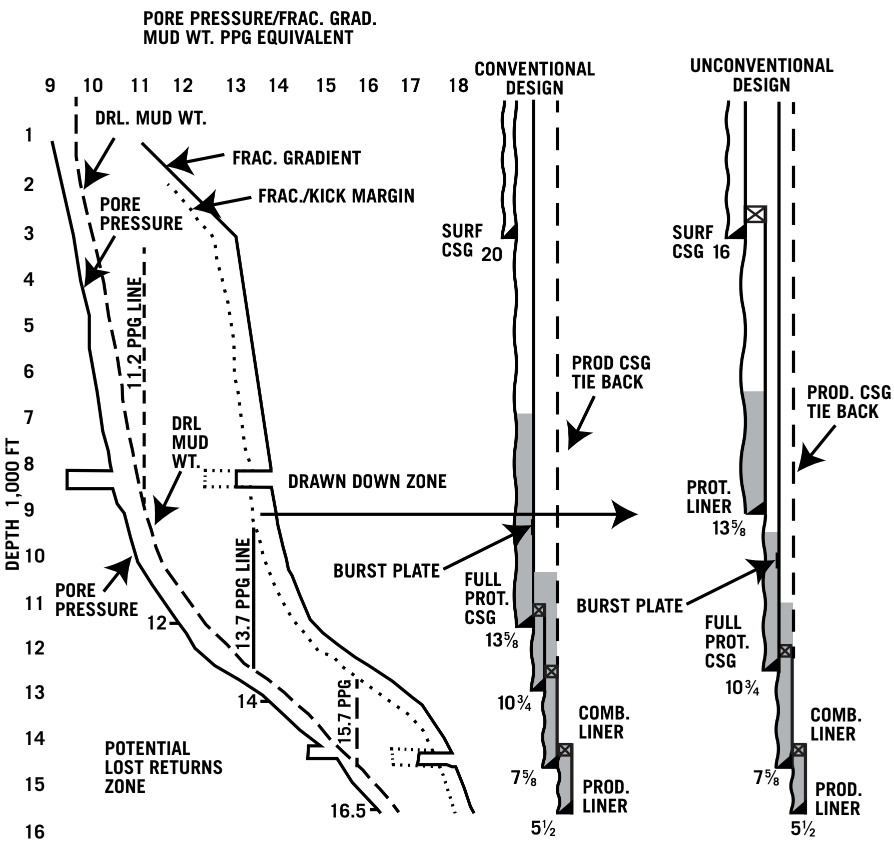


Figure 1.6: Unconventional architecture design comparison to conventional design to address pressure deficiency from larger protective casing size required for conventional design case.

1.10.1 Drilling below the 10 ¾-in. protective casing string

The expected leak-off below the 10 ¾-in. casing at 12,500 ft is about 16.3 ppg with a fracture gradient safety margin of 15.7 ppg. (Refer Figure 1-6.) Since it is anticipated that 16.8-ppg mud will be required to drill to TD, the fracture limit of 16.3 ppg at 12,500 ft will now require for a liner to be set before reaching bottom regardless of whether the loss zone above 14,500 ft is present or not. When drilling below the 10 ¾-in. casing shoe the mud weight will need to be increased to about 15.7 ppg (the fracture safety margin at 10 ¾-in. shoe) when a depth 14,500 ft is reached. At this point it will be necessary to stop and set the same 7 ⅝-in. 39-lb P-110 FJ combination service protective/production liner that was designed in the conventional well case. This liner will be hung from inside the 10 ¾-in. casing from a depth of 12,200 ft. (The combination production/protection service 7 ⅝-in. liner that was designed for the conventional case scenario is valid in this unconventional design case. Because this is the same well, being completed with the same size production casing tubulars under the same pressure and completion scenario used in the conventional design case.) The 10 ¾-in. and the 7 ⅝-in. casing and liner combination at this point in the well will now serve as the protective casing string needed to drill the bottom section of the hole. This smaller diameter combination protective string will make it much easier to meet the same kick design criteria (See Appendix 1C for protective casing unconventional design approach.) that the 13 ⅝-in. x 10 ¾-in. x 7 ⅝-in. protective casing string would not withstand in the conventional design case. The comparison of the two architectural design cases is shown on the right side of Figure 1-6.

The kick scenario for the 10 ¾-in. x 7 ⅝-in. protective string set at 14,500 ft which will be used to drill the pay zones assumes that a kick occurs while drilling near TD with mud weight that is ½-ppg underbalanced. After the well is shut-in the gas migrates or is circulated toward the surface, and the casing shoe set at 14,500 ft breaks down. When the gas reaches the surface it will occupy the top half of the casing. Figure 1C-3 presents the results of the pressure profile calculations as the gas is at various stages of reaching the surface. Curve ABCD represents the highest internal pressure exerted on the casing as the gas comes to the surface when the shoe fractures. Figure 1C-4 presents the differential pressure design curves for the casing for the kick scenario assumed above minus the external back-up pressure support behind the protective string. The casing selected to meet the design pressures are also annotated on the graph. The pipe selected for the 10 ¾-in. casing is 71.1-lb C-95 with MacII connections from the surface down to 3,600 ft and 71.1-lb P-110 from there to 12,500 ft. The combination 7 ⅝-in. liner from 12,200-14,500 ft would be 39-lb P110 with FJ connections. The highest differential pressure design point occurs between 8,600 ft and 9,000 ft where the design criteria assumes that the back-up pressure on the protective casing from the mud in the annulus above the cement top has settled and is only equal to a water gradient. This is a very conservative assumption, but even in this case where the burst requirement is for a differential pressure of just over 8,600 psi, the 10 ¾-in. 71.1-lb P-110 casing selected has a burst capacity of 8,730 psi with a pressure derating of 10% for wear and an added safety factor of 1.2. The casing absolute yield rating is actually 11,640 psi. The 13 ⅝-in. 88.2-lb Q125 used in the conventional design case with comparable safety factors was only rated at 7,500 psi and would not meet this requirement.

1.10.2 Drilling to TD and completing the alternate architecture design well

Drilling to TD below the 7 ⅝-in. dual purpose combination protective/production liner, hung under the 10 ¾-in. casing and completing the well with the 5 ½-in. liner, a 7 ⅝-in. tieback and 3 ½-in. by 2 ⅞-in. tubing will be the same as for the conventional design case. The only difference is a slightly longer 7 ⅝-in. liner and shorter tieback in the alternate case. The pressure and load design for the production casing and the tubing is identical as for the conventional case.

The maximum shut-in differential pressure for the example well case full of gas to the top would be 11,710 psi at the surface and would drop to 8,730 psi at 9,500 ft. Below 9,500 ft, the differential pressure would be further reduced towards TD. The 10 ¾-in., 79.9-lb Q125 casing is rated at 12,100 psi with a 10% wear derating and a 1.2 safety factor for data variations. This design capability could not be matched using the 13 ⅝-in. casing in the conventional design.

Employing an effective wear management program for drilling through the 10 ¾-in. x 7 ⅝-in. protective string and conducting a caliper survey to verify string integrity would allow for the use of this string as the final production casing. This would eliminate the need to run a 7 ⅝-in. production tieback from the top of the combination service 7 ⅝-in. liner below the 10 ¾-in. long string back to the surface to complete the well. Using these new available tubular products would reduce both the complexity of the operations and cost. The design capability using this approach cannot be matched using the 13 ⅝-in. casing as part of the protective string in the conventional design presented in the first part of Chapter 1.

1.11 Wells requiring tubing retrieval subsurface safety valves

Offshore wells and other critical service wells that will require installation of large outside diameter tubing retrievable surface controlled safety valves may necessitate for some of the casing strings outside of the production tubing to be upsized above the depth where the valve will be set. The upsizing is necessary in order to provide sufficient clearance for the OD of the valve and control lines that must be run to the surface. In offshore wells these valves are installed at around 2,000 ft below the mudline to avoid hydrates issues at cold temperatures. On land wells the setting depth for the safety valve may be shallower. For the example case presented here the outside diameter of the safety valve for the 3 ½-in. tubing will be 6-in., which will be too big to run in the 7 ⅝-in. production casing with a 6.3-in. drift. The top of the production casing tieback down to a depth of 2,000 ft can be modified to use 8 ⅝-in. casing to provide the added clearance for the valve. Installing 8 ⅝-in. 58.7-lb HCQ-125 with MACII connections with an ID drift ID of 7.126-in. will provide the necessary clearance and burst capacity to meet the design requirements (13,277 psi burst with a 1.3 SF). The coupling OD for the 8 ⅝-in. MACII connection is 8.97-in. This is too big to use inside the 10 ¾-in. protective casing at the top of the well which has 9.294-in. drift ID; so the top of the protective casing will also have to be upsized to provide added clearance down to 2,000 ft. Substituting 11 ¾-in. 87.5-lb C-95 casing with MACII connections with a drift ID of 10.126-in. and a burst capacity of 7,792 psi with 10% derating for wear and a 1.2 SF for data variance will exceed the burst requirements for the top part of the string to accommodate the added space requirement. Since the top 2,000 ft of the 11 ¾-in. section of the protective casing with MACII connections with an OD of 12.09 in. will be run inside of the 16-in. section of the surface casing with a drift ID of 14.8 in., there will be plenty of clearance for the to accommodate the bigger casing.

Authors' note

New products have come on the market to meet the challenges of today's higher-standard regulatory environment and deeper, higher-pressure well prospects. In the example well just discussed above using the 10 ¾-in. x 7 ⅝-in. protective string to drill to TD for the unconventional design, the operator could choose to design the protective string to withstand full well shut-in pressure with the well full of gas if desired or required. This can be accomplished by using the now easily available standard 10 ¾-in., 79.9-lb Q-125 casing from the surface to 9,500 ft in place of the 71.1-lb P-110 used in the above design. The 79.9-lb Q-125 casing has a burst pressure rating of 16,130 psi. The special drift casing would still allow drilling a 9 ¼-in. hole to set the 7 ⅝-in. liner below it.

1.12 Axial load analysis and design

After designing a casing string for burst and/or collapse pressures and selecting the required weights and grades of pipe needed to handle the pressure requirements the last step in the design is to ensure that the pipe selected is also capable of meeting axial load requirements for the life of the well. High axial loads will also impact the burst and collapse capacity of a casing string under combined loads. Doing a typical axial load design for the tubing and casing strings for the example well are beyond the scope intended in this chapter on well architecture design because the subject is fairly straight forward and is fully covered in Chapter 5 of the before mentioned reference to the Ted G. Byrom book titled "Casing and Liners for Drilling and Completions." To ensure however that the pipe body strength for the weights and grades selected for the casing strings that were landed at the surface for the designs presented in this chapter would meet the axial load requirements a check was done using the design methods outlined in this reference, which indicated that the designs were adequate. If the analysis had indicated a deficiency existed in axial load capacity, different connections are available for the tubulars selected which would exceed the required capacity for the casing. The analysis indicated that LT&C and/or Buttress connections, or where special connections for strength or clearance purposes were noted, all met the load design requirements. In the case of the production tubing and casing strings, premium connections were selected in consideration of their severe leak proof and collapse requirements in the intended high pressure oil and gas service.

1.13 Special considerations

Because generally the highest axial load conditions of a surface landed fixed string of casing or tubing do not occur when they are first landed, most design procedures use installed buoyed weight as the design load and then employ large safety factors (1.6-1.8) to account for future changes that will take place over the life of a well. Load changes caused by higher mud weights and/or pressure and changes in temperature in the casing strings as compared to when they were installed (fixed) can have a significant impact on axial load changes. The axial loads can also alters the pressure containment rating of the string under combined loads. Casing under high tensile loads has lower collapse capacity and casing under high compressive loads has a lower burst capacity. Chapter 10 in this book, entitled "Load and Stability Analysis of Casing Strings", will present a more complete and accurate technique that may be used to determine the changes in axial load and lateral stability of a casing string under different conditions then when they were first installed. When these analyses indicate high axial loads due to changes in operating conditions, the design engineer should make a final check on how a high compressive or tensile load on a casing string design will affect its burst and collapse rating under combined loads. In some cases it may be necessary to tweak the design to account for the reduced burst and/or collapse ratings due to combined loads. See Chapter 8 of the referenced Ted Byrom book, "Casing and Liners for Drilling and Completion," for procedures available to determine reduced collapse and/or burst capacity for casing under high combined loads.

1.14 Surface casing and conductor/conductors design

Since the alternate architectural design case scenario for the design example case for burst loads on the surface casing was done based on its use as part of a protective string to drill to 12,500 ft, no other analysis is required from an internal or external pressure perspective. Any internal pressure design scenario while using the surface casing to drill to 9,000 ft before hanging the 13 ⅝-in. liner at the base of the 16-in. casing will be much less severe than when it is used to drill the well down to 12,500 ft. The pipe body and connection capacity for the upper section of surface casing and the conductor/conductors selected do, however also need to be designed to carry the maximum compressive loads for all surface landed strings under the highest future load conditions that may be generated by future operations. The depth to which the load design applies and the distribution of compressive loads between the surface and conductor strings should be based on soils analysis work. The highest axial load conditions transferred to the surface casing and conductors will occur when higher mud weights and or pressure are introduced in any surface landed string. The same is true when any pumping is done with cool fluids for extended periods at high rates and pressures. Doing the necessary analysis to determine these loads for the example case design is beyond the scope of this chapter. Chapter 10 in this book entitled "Load and Stability Analysis of Casing Strings" will present an explanation and a method for doing the necessary calculations to establish the loads on a fixed string under varying conditions of pressure and temperature. These loads can then be used to complete the axial load designs for both the landed strings and the casing supporting the landed loads.

1.15 Closure

The purpose for this chapter is to take the reader on a mental journey of what is required to put a well design plan together that considers and accounts for unforeseen anomalies when planning and drilling a complex well. What I have also tried to do is to provide detailed examples that walk the reader through the tedious and sometimes repetitive process of doing some of the calculations needed to reach an answer or conclusion. In today's world of computers many for the calculations included here are done by a machine with input from the designer. Using a computer to hone-in on a trial-and-error calculation process or, as for example, to recalculate a more accurate compressibility factor (Z) for gas as it is impacted by different temperature and pressure conditions to lead to a more refined answer is a good thing. I am of the opinion that this is something that we need to take advantage of when it is available. However I also believe that much of the learning process actually comes from grinding through the numbers, doing the trial and error calculations, and seeing why the answers we come up with are what they are. This also helps stimulate thinking that sometimes leads to better alternative solutions.

APPENDIX 1A: Production tubing and casing design

1A.1 Discussion

Figure 1A-1 of Appendix 1A shows the configuration for the design of the example well described in Chapter 1 on Well Architecture Design, including the various casing setting depths and sizes for a completed well. This appendix presents the design criteria that will be used for the tubing and production casing strings, establishes the resulting design loads acting on the strings and then shows how selections of weights and grades of the tubulars are made to meet the design loads. There are many good sources available to obtain performance properties for tubular goods from pipe manufactures, service company manuals, API and from operator manuals. For the cases presented here, for convenience, the data was obtained from tables available from TenarisHydril online.

1A.2 Production tubing design

Paragraph 1.8 in Chapter 1 entitled Tubing and Casing Design Procedures, described that in most cases production engineers are charged with the responsibility for providing the specifications for the tubing size and configuration that will be required to complete a well. The determination is made based on the anticipated production type, expected or desired rates, and operating parameters such as pressure, temperature and well depth. In the example case being used here (shown in Figure 1-5 of Chapter 1 and in Figure 1A-1 in this appendix) it is assumed that the production engineers have determined that the tubing size that will be needed for this well should be comprised of a combination tubing string of 3 ½ in. down to at least 11,000 ft, and then 2 ⅞ in. below that depth down to an expected packer setting depth

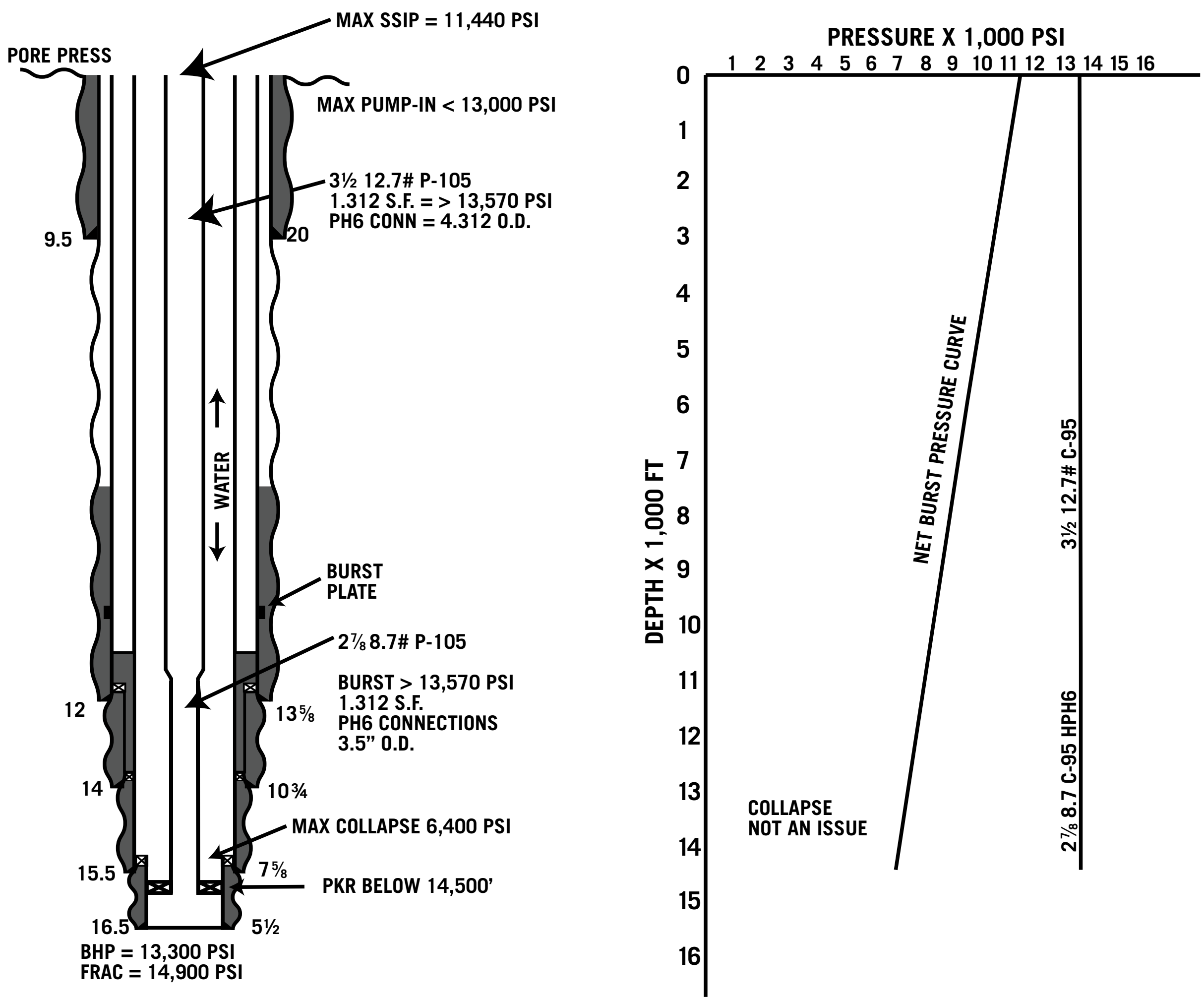


Figure 1A-1: Production tubing design (conventional design); max ssip & pump-in to kill criteria water outside; max collapse tbg empty & water pkr fluid outside.

of 14,500 ft. Because the production tubing will operate in severe pressure and gas service the connections will be premium grade with an OD of 4-4 ½ in. for the 3 ½-in. pipe and an OD of 3 ½ in. for the 2 7/8-in. pipe. As discussed in the well architecture design section, the sizes for the production casing selected to house the tubing, and to serve as a back-up string to contain well pressure in the event of a tubing leak will comprise the following:

- 5 ½-in. production liner on bottom to accommodate 2 ⅞-in. tubing down to the packer;
- 7 ⅝-in. production casing above 14,500 ft, to house the remainder of the 2 7/8-in. tubing up to 11,000 ft;
- 3 ½-in. tubing the rest of the way from there to the surface.

The criteria used to design for burst pressure in the tubing on a well should always be based on the maximum pressure that the tubing will be subjected to over the life of the well when producing, shut-in and/or during pumping operations such as killing the well or doing a stimulation treatment. In the example well case introduced in Chapter 1, the maximum surface shut-in pressure will be the maximum bottomhole pressure minus a gas gradient to the surface. The bottomhole pressure of a producing formation at 15,500 ft requiring 16.5 ppg mud to drill it is 13,300 psi. When the well is shut in and full of gas, assuming a light gas gradient of 0.12 psi/ft internally to 15,500 ft, would result in a gas hydrostatic head of 1,860 psi from the surface to the bottom of the well. This hydrostatic head would then reduce the bottomhole pressure to a maximum surface shut-in pressure of 11,440 psi. This surface shut-in pressure value is plotted at the top of the pressure vs depth curve shown on the right side of Figure 1A-1. The pressure at the top on the tubing casing annulus is "0" when the well is producing or shut-in. The pressure inside the tubing at the packer set at 14,800 ft would be 13,200 psi. (This is the calculated surface shut-in pressure of the tubing plus a gas gradient of 0.12 psi/ft from the surface to 14,800 ft.) The pressure on the tubing/casing annulus at the packer, with water as a packer fluid, would be 6,400 psi. The net burst pressure difference in the tubing at the packer is then 6,800 psi. (13,200 psi – 6,400 psi = 6,800 psi) This point is plotted at the base of the net pressure differential curve for the tubing on the graph on Figure 1A-1. Pumping into the well, in a killing operation to break the well down, would require a pressure at the formation face equal to the fracture gradient of 18.5 ppg at 15,500 ft, which is 14,900 psi. The surface pump-in pressure into the well initially would be expected to be higher than the tubing static shut-in pressure of 11,400 psi. Depending on the rate, however, because pumping would be done using a fluid in the tubing, even water would provide a 6,700-psi hydrostatic head assist, or a surface pump-in pressure of 8,180 psi, not taking friction into account. A more rigorous pressure calculation for a stimulation job or pump-in procedure should be done to get a better handle on the pumping pressures, but for this hypothetical design case a good estimate for a pump-in pressure value will likely be less than 13,000 psi. Additionally during any pumping procedure into a well it is also a common good practice to apply pressure on the tubing/casing annulus, further reducing the differential pressure on the tubing, and therefore reducing the net burst load.

The collapse design criterion for the tubing assumes that the perforations plug from the outside while the well is producing and the tubing pressure inside drops to "0." When this happens the maximum collapse pressure on the tubing backside, (tubing/casing annulus), will be the hydrostatic pressure of the packer fluid down to the packer. With water being used as the packer fluid, the maximum collapse design pressure on the tubing casing annulus is 6,400 psi; therefore collapse is not the governing load for the tubing design. Because burst loading will govern the design, as annotated on Appendix 1A Figure 1A-1, the tubing selected for the top section down to the crossover at 11,000 ft will be 3 ½-in. 12.7-lb C-95 with HPH6 connections (4.312 in. OD) with a burst rating of 13,570 psi using a safety factor of 1.312. For the lower section of tubing below 11,000 ft the tubing selected will be 2 ⅞-in. 8.7-lb C-95 with HPH6 connections (3.5-in. OD) The burst rating for this pipe using a safety factor of 1.312 is also 13,570 psi.

1A.3 Production casing and liner design

The criterion for designing the production casing in burst assumes that a tubing failure occurs and the maximum shut-in pressure of the tubing is then transferred to the top of the closed casing. Figure 1A-2 shows the well design and the pressure curves for the design criteria. The shut-in pressure at the surface would be applied on top of the packer fluid in the annulus and act as a burst load on the production casing down to the packer. Maximum surface pressure with a tubing failure, if the well is shut in, would be equal to 11,440 psi. The pressure applied to kill the well by pumping into it initially could be slightly higher to force gas into the formation downhole, but the surface pressure would soon start to fall as fluid would begin to fill the well. In any case however, the chance of the pressure ever exceeding 13,000 psi is not likely. Because the tubing has an absolute burst capacity that is very high the chances of failure in the base case are very low. During a pumping operation to kill the well it is usually possible to reduce the initial pump-in pressure to a much lower value by lubricating mud into the well. This will reduce the pressure at surface and allow pumping into the well at pressures that are well below the casing pressure rating while killing the well. For very high pressures in excess of what the well will normally shut in at, which may only be experienced during a stimulation treatment (where the excess pressure is due to pumping friction), a relief valve system can be installed on the casing. This relief system will

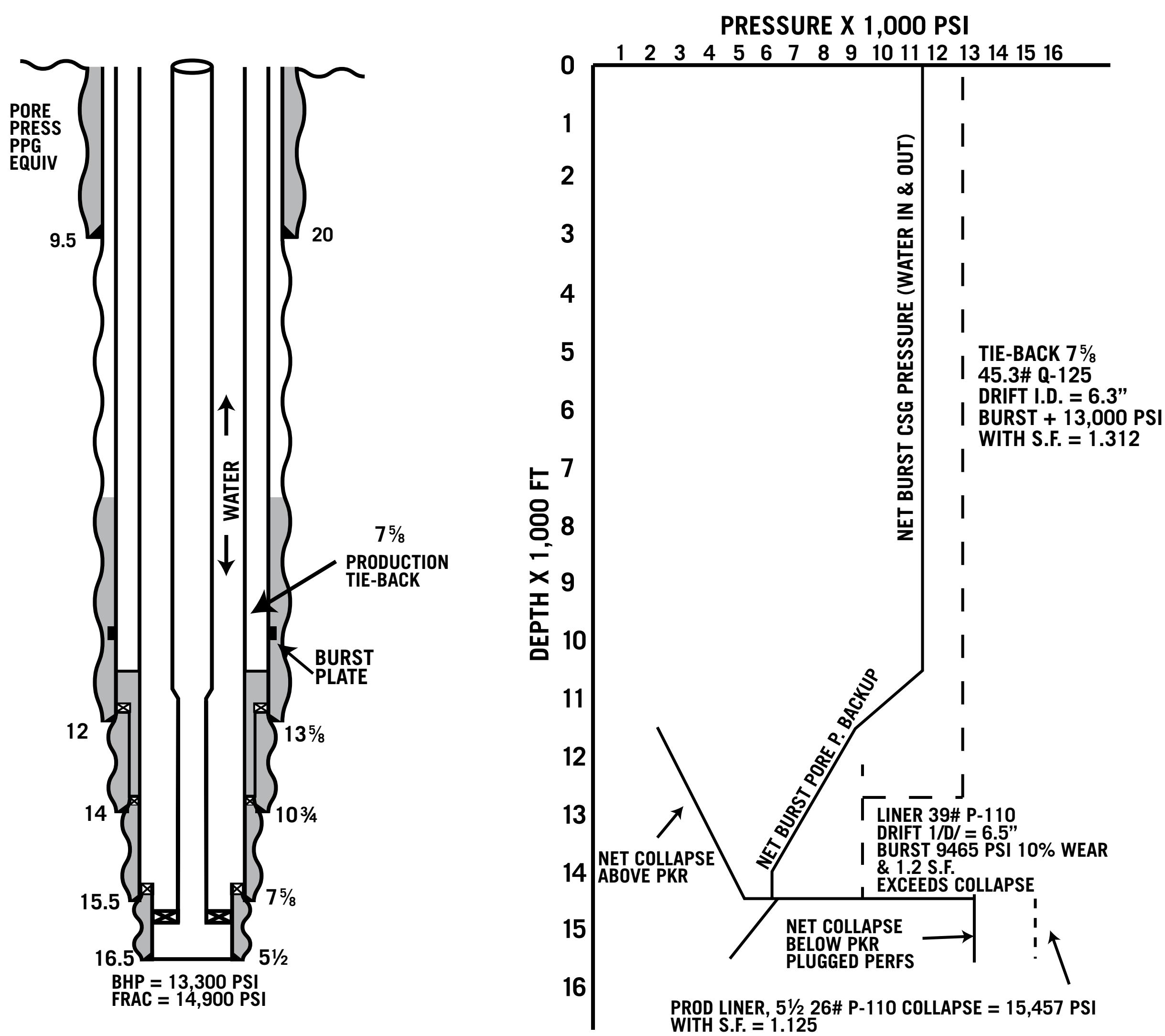


Figure 1A-2: Production casing design (conventional design). Maximum burst (tubing failure) equals 11,440 psi at the surface of the production casing (at zero depth). Outside, assume water packer fluid and settled mud. This assumes water from the surface to the cement top. The pressure outside the casing and below the top of the cement equals the pore pressure (PP).

The collapse design equals the pore pressure at depth outside the casing minus the water gradient inside the casing to the packer, as follows:.

Depth (ft)	Max PP outside (psi)	Water inside (psi)	ΔP (psi)
11,500	7,176	4,981	2,195
13,000	9,464	5,631	3,832
14,500	11,687	6,280	5,400

Below the packer = plugged perforations, which results in internal pressure of "0" psi in the casing; outside pressure = 16.5 x 0.052 x 15,500 = 13,300 psi. This is the maximum collapse below the packer.

serve to limit the maximum allowed pressure that can be exerted on the casing if a tubing failure occurs while pumping. In a case like this, stopping the pumps would immediately reduce the maximum pressure at the surface to only the well's bottomhole pressure minus the fluid gradient in the well, and this would then automatically allow the relief valve to close, shutting the well in on the casing. Alternatively, a higher pressure design can be selected that will withstand the higher pressures without a relief system for these rare cases, but this can be expensive and unnecessary as long as a good pressure management plan can be designed and implemented.

The internal burst pressure design conditions for the production casing down to the packer assumes that the well has water as a packer fluid. The annotated differential pressure design load curves for both burst and collapse using the criteria described above for the production casing are shown on the right side of Figure 1A-2. The net burst curve has a surface shut-in pressure of 11,440 psi at the surface and then assumes that the fluid inside the production casing down to the packer depth at 14,500 ft is water. The fluid outside the production casing down to the cement top at 10,500 ft is mud that was left above the cement top of the 7 ⅝-in. tieback casing. This mud will settle over time but because there is no way of determining what the mud weight distribution might be, the safe bet for casing design purposes is to assume that it is water at any depth above the cement top at 10,500 ft.

A logical criterion that can be used for pressure support behind the casing below the cement top is to assume that it will be at least equal to the pore pressure of the formations outside the outermost casing. Even using this approach it is a conservative assumption, because there is cement and other casing between the production string and the outer formations that act as a composite structure to help contain the internal pressure. This being the case, the minimum pressure support for the composite structure cannot be less than that of the pressure backing up the outermost casing string. The net burst casing design curve for the criterion discussed above is shown on the graph on Figure 1A-2. The curve above 10,500 ft (top of cement) reflects the assumption that the maximum surface shut-in pressure of the well acting inside the casing is on top of a water packer fluid and that the back-up pressure, outside of the casing down to the cement top for the 7 ⅝-in. production casing tieback is also a water gradient. The curve below 10,500 ft reflects the same shut-in pressure acting on top of the water packer fluid inside all the way to the packer. The back-up pressure support outside of the casing below the cement top, however, is assumed to be equal to the pore pressure of the formations in the well at the given depth.

The collapse design criteria for the 5 ½-in. production liner run in the open hole on bottom, and the production casing from the top of the liner to the surface, assumes that external pore pressure is acting on the outside of the string. The worst case collapse condition for the production casing above the packer assumes water inside and pore pressure outside. The worst case collapse design conditions for the production liner below the packer assumes that the perforations plug and the pressure inside the liner is "0."

The results of the differential pressure between the external collapse pressure and internal support pressure acting on the casing are shown on the annotated net collapse pressure design curve in Figure 1A-2. Collapse pressure for this well is only critical in the 5 ½-in. production liner portion of the well below the packer where plugged perforations would exert a collapse pressure on bottom equal to formation pressures with "0" pressure inside. Above the packer maximum collapse pressure outside is equal to formation pressure, but because the well has water inside as a packer fluid the differential from outside, (in collapse), is much reduced compared to the conditions below the packer. The table at the bottom of Figure 1A-2 provides the data for the differential collapse pressure curve over the critical bottom portion of the well casing above the packer. The net collapse pressure acting on the liner below the packer is also calculated and shown below the table.

The last step in this design process is to select the weights and grades of pipe that will provide the casing strength required to meet the loads. (Refer to Appendix 1A, Figure 1A-2.) Using the TenarisHydril casing properties tables a selection of 5 ½-in. 26-lb P-110 Flush Joint casing can be made for the production liner. This casing has a collapse rating of 15,457 psi with a safety factor of 1.125. Note that highest collapse load on this pipe will be 13,300 psi which is the expected pressure in the producing zone. To meet the burst load requirements above the 5 ½-in. production liner, a selection of 7 ⅝-in. 39-lb P110 Flush joint casing for the combination protection/production liner from 14,500-12,700 ft can be made. If the liner were to be hung from a shallower depth than this the same casing would meet the burst requirements up to a depth as shallow as 11,500 ft. The burst rating for the selected 7 ⅝-in., 39-lb P-110 casing is 12,620 psi. After applying a 10% derating factor to allow for wear caused by drilling operations and considering a design variation factor of 1.2, the design pressure rating for the casing becomes 9,465 psi. The remainder of the production casing above the liner at 12,700 ft will be run as a tieback string back to the surface. The casing selected for this section is 7 ⅝-in. 45.3-lb Q-125 with premium connections (MACII) for superior sealing capability in gas service. The burst capacity for this portion of the string is 13,000 psi with a safety factor of 1.312. The burst rating for the casing selected exceeds the requirements, as noted, when comparing the design curves to the annotated casing burst capacity ratings on Figure 1A-2. Note that there is a trapped annulus in this design case between the 7 ⅝-in. production tieback and the protective casing. This annulus space will need to have a pressure relief system installed at the surface in a land well application, or have a burst plate installed deep in the protective casing string to allow for fluid expansion under producing operations to avoid the possibility of collapse of the production casing or burst of the protective casing.

APPENDIX 1B: Conventional protective casing and liners design

1B.1 Discussion

The criteria used to design a protective string composed of casing and extension liners below for the example well case in this book (Refer to Figure 1-3 Chapter 1), is based on a modified approach to one presented in the Gulf Publishing Drilling Series book by Ted G. Byrom, entitled "Casing and Liners for Drilling and Completions". The Byrom book describes a process that is used by some operators, which sets a predetermined surface pressure as a limit either by BOP or wellhead ratings and then selects the casing weights and grades and the setting depths for the string no deeper than where the shoe will be the weakest failure point in the well if an extreme pressure kick were to occur. In simpler wells that do not require setting multiple liners to drill the well this approach may be acceptable. In very complex wells with extreme pressure build-up with depth that will require setting multiple liners to reach TD using this approach may limit the ability to drill the well. The approach for designing a well using the BOP and wellhead rating as a limit is neither recommended nor rejected in the Byrom book, but rather is mentioned as one used by some operators usually as a cost savings measure or because of equipment availability limitations.

The modified approach used in this book is not to limit the pressure that can be handled at the surface to the containment capability of predetermined equipment limitations. Instead, the goal is to design the BOPs, wellhead and protective string as a system able to withstand the pressures that would be caused by an unexpected massive influx of gas when drilling below the protective casing string. The setting depth for the first protective casing out from under surface pipe, and for every casing shoe thereafter, are pushed to the deepest depth allowed by the fracture gradient limit below the last open shoe in each hole section. Under this design scenario, the internal pressure resulting from shutting-in a kick influx and bringing the extreme high pressure gas to the surface, either by circulating or by the gas rising upward on its own (migrating towards the surface due to buoyancy), would preferentially cause the deepest exposed shoe formation to fracture before a failure can occur in the well casing or surface equipment. If after using this approach it is not possible, in the extreme case, to find equipment or casing with sufficient capacity to meet the pressure requirements, then an alternative could be to design the lower portion of the protective casing with a weak joint or burst plate to provide pressure relief. This design approach would serve in an extreme or unexpected case to preferentially cause a deep pressure relief in the casing string above the shoe opposite formations with a lower fracture gradient than the shoe.

1B.2 Worst-case scenario for protective casing design pressures

A worst case scenario for the occurrence of a gas kick in the base case described above would be one where the well fractures at the shoe after being shut in and the casing is left full of gas with no mud remaining in the well. This would be a design where the surface pressure is equal to the bottomhole pressure of the fractured shoe minus a gas gradient to the surface. This makes for an easy design but often it may not be possible to find protective casing (large diameter pipe) that can withstand such high pressures. From a practical standpoint it is also not very likely that a situation where the casing is totally void of any fluid will occur because usually some fluid, even water, can be put in the well. Each operator will normally make the decision on the criteria to use for a worst case design based on their knowledge of the area they are drilling and other internal risk assessment decisions.

In many jurisdictions, the design scenario selected by the operator must be approved by appropriate regulatory agencies. For the US Outer Continental Shelf (OCS), for instance, the Bureau of Safety and Environmental Enforcement (BSEE) must approve the permit to drill. BSEE allows the operator to select the worst case scenario and to submit the design without strict specific guidelines, other than that the scenario must be severe and based on data for the expected well pressures and complexity. Cases submitted must be defended or changed if a permit is not granted as originally submitted.

To demonstrate how the approach discussed above is used to design the protective casing string and surface equipment, the following very severe well-kick scenario will be examined:

- A deep well drilling below protective casing encounters high pressure and an unexpected gas influx into the wellbore occurs;
- The well is shut-in;
- While the well is shut-in the gas rises towards the surface;
- As the gas rises the well pressure increases and causes the well to breakdown at the deepest casing shoe;
- When the gas reaches the top of the well it fills the top half of the protective casing string, and mud fills the casing from the halfway point down to the fractured shoe.

Because gas is lighter than mud, the gas can rise toward the surface either by trying to circulate the well, or on its own due to migration (buoyancy), or both, bypassing the mud. The gas would bring high bottomhole pressure towards the

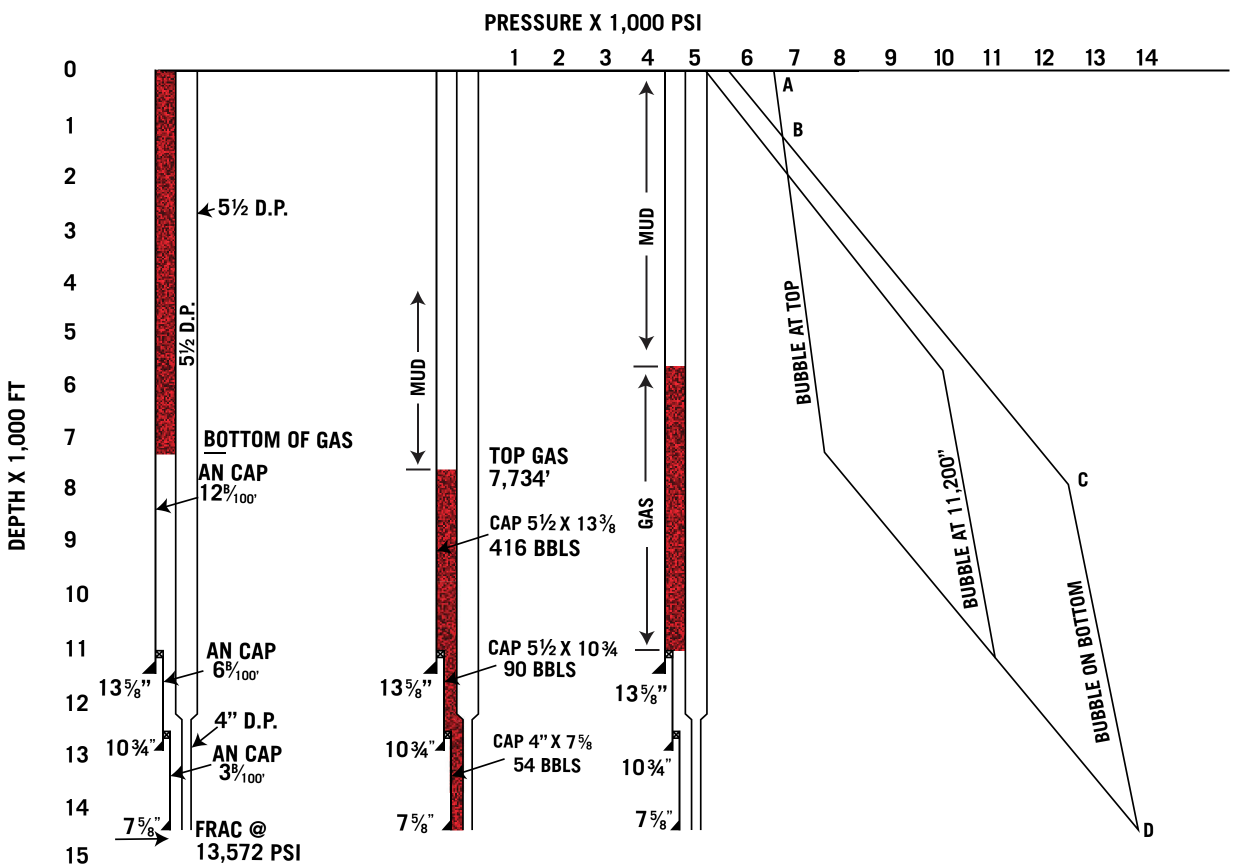


FIGURE 1B-1a	FIGURE 1B-1b	FIGURE 1B-1c
CASE I BUBBLE AT TOP	CASE II BUBBLE AT BOTTOM	CASE III BUBBLE AT 11,200'
SSIP = 6,644 PSI	SSIP = 5,859 PSI	SSIP = 5,222 PSI
h_T = 0 FT	h_T = 7,734 FT	h_T = 5,659 FT
P_T = 6,644 PSI	P_T = 12,288 PSI	P_T = 9.931 PSI
P_B = 7,540 PSI @ 7,250 FT	P_B = 13,572 PSI @ 14,500 FT	P_B = 10,826 PSI @ 11,200 FT
FRAC. DPT. = 14,500 FT	FRAC. DPT. = 14,500 FT	FRAC. DPT. = 14,572 FT
P_{frac} = 13,572 PSI	P_{frac} = 13,572 PSI	P_{frac} = 13,572 PSI
VOL BUBBLE = 870 BBLS	VOL BUBBLE = 560 BBLS	VOL BUBBLE = 665 BBLS

Figure 1B-1: Kick pressure profile curves for gas influx resulting in 870 bbl gas volume at the surface after formation fractures at 14,500 ft with 13,572 psi (equivalent mudweight 18 ppg).

top which then would force fluid into the fractured shoe, allowing the bubble to expand. Once the gas reaches the top, the pressure in the closed system would equalize and the surface pressure would be equal to the bottomhole pressure at the fractured zone minus the gas and mud gradient left in the casing. This is a very severe case because the kick is assumed to occur with drillpipe in the hole so that mud and or heavy pills can be pumped underneath the gas to try to control the well and reduce the pressures that result from the worst case design assumptions.

1B.3 Internal casing pressure profile for the worst kick scenario

The initial step in designing the casing, BOPs and wellhead to withstand the assumed kick scenario is to calculate the pressure profile in the casing string for the gas influx as it enters the well, fractures the shoe and works its way to the surface. This can be done by using the following two ideal gas law equations and the known data for the formation fracture pressure limit at the deepest shoe and the amount of gas and mud in the casing.

The two ideal gas law equations are as follow:

$$P_T = P_B \, e^{\left(\frac{m(h_T - h_B)}{ZR\,T_{ave}}\right)} \qquad \textbf{Equation 1B-1}$$

This ideal gas law equation is used to determine the pressure at the top of a gas column, P_T, when the following is known:

- The pressure at the bottom of the gas column, P_B;
- The gas properties;

- The average temperature conditions in the gas column;
- The height of the gas column.

In general a good choice for the type of gas influx is to assume that the gas is methane, which will be used for this example.

Determining P_T, and knowing P_B and the height of the gas column (H_G) will yield the gas gradient (GG) of the column.

P_T = pressure at the top of the gas bubble, psi
P_B = pressure at the bottom of the gas bubble, psi
h_T = depth to the top of the bubble, ft
h_B = depth to the bottom of the bubble, ft
H_G = height of gas (h_B - h_T), ft & GG = gas gradient, psi/ft
Z = compressibility factor for methane; assume = 1 (for simplification)
R = 1,544 lb/ft/mole °R, where °R = °F + 460; (conversion factor for oilfield units)
M = molecular weight for methane = 16 lb/mole
T_{avg} = average temp. gas column (midpoint), °R
Formation Temp. Gradient (given) = 1.5°F/100 ft

$$P_1V_1T_2 = P_2V_2T_1 \qquad \textbf{Equation 1B-2}$$

This equation represents the fixed relationship that exists for a given mass of gas under different conditions of temperature and pressure.

P_1 = average pressure of the gas column at condition 1, psi
P_2 = average pressure of the gas column at condition 2, psi
V_1 = volume of gas under condition 1, bbl
V_2 = volume of gas under condition 2, bbl
T_1 = average temp gas at condition 1, °R
T_2 = average temp gas column at condition 2, °R
°R = °F + 460

1B.4 Example well kick pressure profile calculations conventional well design

Appendix 1B Figure 1B-1 shows the example well used in Chapter 1 (Figure 1-3) with the kick example described above at several stages as the gas bubble migrates or is circulated to the surface after the well is shut in on the protective casing string. The scenario assumes that a ½ ppg kick occurs when drilling through the pay section with 16 ppg mud in the hole. A gas influx occurs and the well is shut in. As the gas comes to the surface, either by circulating the well or due to migration, the well breaks down at the casing shoe. In Figure 1B-1a the gas bubble has reached the surface of the protective string and its volume occupies the top one-half of the casing from 7,250 ft to the surface. This is the total height of the gas bubble (H_{G1}) when the gas is at the top of the well. Drilling mud (16 ppg) fills the casing from 7,250 ft to the fractured casing shoe at 14,500 ft. This well condition will be Case I for the kick profile calculations for the example well. The first step is to calculate the casing pressure profile when the gas has reached the surface using the gas law equations. The annular capacity between the drillpipe and the 13 ⅝-in. casing is 12 bbl/100 ft. The volume of the gas = 7,250 ft x 12 bbl/100 ft = 870 bbl. Pressure at the fractured shoe at 14,500 ft. P_{frac}= 18 ppg x .052 x 14,500 ft = 13,572 psi.

Pressure at the bottom of the gas bubble (P_B), working from the fractured shoe up, is equal to the fracture pressure at the shoe minus the mud head from the shoe to the bottom of the bubble. P_B = 13,572 – (16 ppg x 0.052 x 7,250) = 7,540 psi

Calculate the pressure at the top of the bubble using the ideal gas Equation 1B-1:

$$P_T = P_B\, e^{\left(\frac{m(h_T - h_B)}{ZR\,T_{ave}}\right)}$$

P_T = pressure at the top of the gas column
P_B = 7,540 psi at the bottom of the gas column
h_T = depth to the top of the gas column, surface 0
h_B = depth to the bottom of the gas column - 7,250 ft
H_G = height of gas (h_B – h_T), ft
GG = gas gradient, psi/ft
Z = gas compressibility factor = 1

$$R = 1{,}544 \ \frac{\#\ ft}{mole\ °R} \ \text{conv. factor oil field unit}$$

M = molecular mass of methane = 16 #/mole
T_{avg} = average temp. gas column °R

$$\text{Temp. grad (given)} = 80 + 1.5\ \frac{°F}{100\ ft}$$

$$T_{avg} = 80 + \left(\frac{1.5\ °F}{100\ ft} \times \frac{7{,}250\ ft}{2}\right) + 460 = 594\ °R$$

$$P_T = 7{,}540\, e^{\left(\frac{16(0 - 7{,}250)}{1 \times 1{,}544 \times 594}\right)}$$

P_T = 6,644 psi, top of the gas
P_{frac} = 13,572 psi @ 14,500 ft

$$\text{Gas Grad (GG)} = \frac{P_B - P_T}{H_G} = \frac{7{,}540 - 6{,}644}{7{,}250}$$

Gas Grad (GG) = 0.123 psi/ft

Plot the pressure profile for Case I on the right side graph section of Figure 1B-1. The data calculated above for the pressure profile curve is listed below Figure 1B-1a.

Case II: Next calculate the pressure profile for the gas bubble when it was at the bottom of the protective casing string just above the shoe at 14,500 ft. Use Equation 1B-2 and the known volume, temperature and pressure of the gas bubble when it reaches the surface (Case 1), to determine what the compressed volume of the gas was when it was downhole under higher temperature and pressure conditions. The mass of the gas will be constant but in order to calculate what the volume was downhole it will first be necessary to make an estimate of what it was in order to determine what the temperature and pressure conditions were when the gas occupied the bottom of the casing string. This is a trial and error process using the gas equations, as follows, to hone in on the right answer.

Estimate bubble volume on bottom is 65% of volume when it reaches the surface.

Estimated volume = 870 bbl x 0.65 = 565 bbl

Determine bubble height for 565 bbl. Ref. Figure 1B-1b.

Capacity of the annulus from 14,500 ft to 12,700 ft
(4 in. DP x 7 ⅝-in. liner) = 54 bbl (1,800 ft)

Capacity of the annulus from 12,700 ft to 11,200 ft
(5 ½-in. DP × 10 ¾–in. liner) = 90 bbl (1,500 ft)

Balance of the gas above 11,200 ft = 565 bbl – 54 bbl – 90 bbl = 421 bbl. Height of 421 bbl in the annulus of the 5 ½-in. DP X 13 ⅝-in. casing = 421 bbl × 100 ft/12 bbl = 3,508 ft

Total gas column height (H_{G2}) = 1,800 ft + 1,500 ft + 3,508 ft = 6,808 ft

Top of the bubble = 14,500 ft – 6,808 ft = 7,691 ft

Midpoint of gas column = 7,691 ft + 6,808 ft/2 = 11,095 ft

Average pressure at the bubble (midpoint) = pressure at bottom of gas column (frac pressure at shoe) – gas gradient to the midpoint of the gas column. Assume gas gradient is 0.15 psi at higher downhole pressure than when gas is at the surface which was 0.123 psi for case I.

Average gas column pressure
P_{2avg}= 13,572 psi - 0.15 x 6,808 ft/2 = 13,061 psi

Average temperature at midpoint of gas column =
T_{2avg} = 80° + (1.5°F/100 ft) x (11,095 ft) + 460 = 706°R

Calculate V_2 using gas law Equation 1B-2
$P_1 V_1 T_2 = P_2 V_2 T_1$ rearrange equation to solve for V_2
$V_2 = P_1 \times V_1 \times T_2 / P_2 \times T_1$

Known data from Case I
P_{1avg} = SSIP + GG.X (H_{G1}/2)
P_{1avg} = 6,644 + 0.123 x 7,250/2 = 7,089 psi

V_1 = 870 bbl
T_{1avg} = 594 °R

Substitute in rearranged Equation 1B-2 and solve for V_2:

V_2 = 7,089 x 870 x 706/13,061 x 594
V_2 = 560 bbl, Assumed 565 bbl. This is a good close estimate.

Use the calculated volume of gas, V_2, in Equation 1B-1 to calculate actual gas bubble properties under downhole conditions.

(Next, refer to Figure 1B-1b.)

Calculate the height that 560 bbl of gas will occupy above the shoe at 14,500 ft. From the prior calculations, annular capacity of the well from 14,500 ft to the top of the 10 ¾-in. liner at 11,200 ft is 144 bbl. The distance from 14,500 ft to the top of the 10 ¾-in. liner is 3,300 ft. The balance of the 560 bbl of gas, (560 – 144 = 416 bbl), will be above in the 5 ½-in. DP x 13 ⅝-in. casing annulus with the annular capacity of 12 bbl/100 ft. The gas height above 11,200 ft = 416 bbl x 100 ft/12 bbl = 3,466 ft.

The top of the gas column = 11,200 ft – 3,466 ft = 7,734 ft

The total gas column height H_{G2} = 3,300 ft + 3,466 ft = 6,766 ft

Now using gas law Equation 1B-1 and the results from Case II, calculate the pressure at the top of the gas column.

$$P_T = P_B\, e^{\left(\frac{m(h_T - h_B)}{ZR\, T_{ave}}\right)}$$

P_B = 13,572 psi frac pressure at shoe
h_T = 7,734 ft
h_B = 14,500 ft
M = 16 lb/mole
Z = 1
R = 1,544 #-ft./mole °R Conversion to oil field units
T_{2avg}.= 706°R

$$P_T = 13{,}572\, e^{\left(\frac{16(7{,}734 - 14{,}500)}{1 \times 1{,}544 \times 706}\right)}$$

P_T = 12,288 psi @ 7,734 ft

Gas Gradient = $(P_B – P_T)/(h_B-h_T)$
Gas Gradient = (13,572 – 12,288)/(14,500 – 7,734)
= 0.189 psi/ft

SSIP = Fracture pressure – GG × gas height – mud gradient x mud height

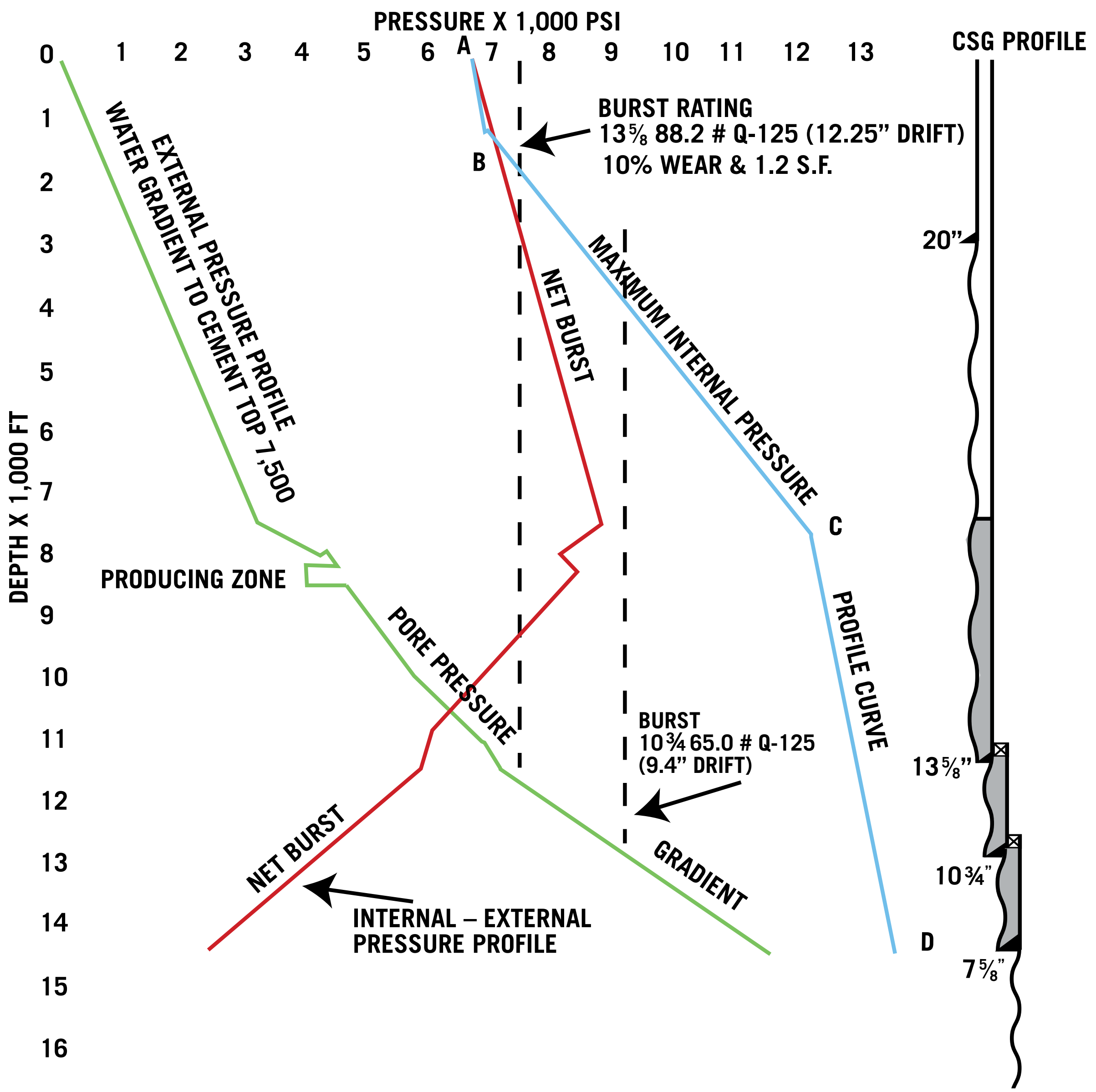


Figure 1B-2: Protective casing and liners design for max kick/differential pressure. Worst case 870 bbl kick at the surface after formation fractures at last caing shoe (conventional architecture design).

SSIP = 13,572 psi – (0.189 x 6,677) – (16 × 0.052 x 7,734)
= 5,859 psi

Plot the profile on Figure 1B-1.

A Case III was done for when the bottom of the gas bubble migrating towards the top has reached the top of the 10 ¾-in. liner top at 11,200 ft, using the same procedures as for Case I and Case II. The number crunching of the Case III example however is not included in this discussion because it would not add anything new to the example. The pressure profile for Case III is however plotted on Figure 1B-1 and the data results are shown at the bottom of Figure 1B-1c.

1B.5 Conclusions drawn from the pressure profile curves

The highest internal pressure in the top 1,000 ft of casing occurs when the gas reaches the top. The highest internal pressure for the remainder of the string occurs when the bottom of the bubble is at the bottom of the protective string. The pressures profile for the intermediate case when the bubble is moving up does not result in higher pressures at any point. The reason that the pressures are the highest for most of the string when the gas is on bottom is because the bubble height in the smaller geometry of the hole is almost as tall as when the gas reaches the top even though the volume is two-thirds of what it is when it reaches the top. The pressure at the bottom of the gas column when it is on bottom is equal to the frac pressure of 13,572 psi, but because the gas gradient is low (relative to mud) the pressure at the top of the gas column is only reduced by the gas gradient of the column which is 1,282 psi. This results in a pressure of 12,288 psi at the top of the gas at 7,734 ft. Curve ABCD then defines the maximum internal pressure design case.

1B.6 Establishing the net differential pressure profile for the casing design

The next step in designing the casing string is to determine the differential pressure vs depth that will be exerted on the protective string composed of the casing and liners by the kick scenario contemplated in the above example. This can be done by first establishing and then subtracting the external pressure profile (back-up pressure) from the internal pressure profile vs depth from the top of the protective casing string to the shoe set at 14,500 ft. Appendix 1B Figure 1B-2 shows the well configuration and the internal and external pressure vs depth design case. The external pressure profile vs depth below the cement top of the protective casing at 7,500 ft was obtained from pore pressure information in Figure 1-3 from Chapter 1 for the example well case used in the Well Architecture Design discussion and in this section on protective casing design. Curve ABCD (shown in blue) represents the internal maximum pressure profile obtained from the previous exercise, paragraph 1B.4 above, which establishes the highest internal pressure that the casing will see while circulating out the massive influx.

As indicated on the graph, labeled external pressure profile, (shown in green) the back-up pressure gradient in the annulus behind the 13 ⅝-in. casing assumes a water column from the surface down to the cement top at 7,500 ft. The casing was cemented with 12.5-ppg mud left in the hole above the cement top. Over time however, some settling of the solids can occur leaving a light column of fluid at the top for some distance and heavier mud towards the bottom. Because there is no way of determining either the weight or the distribution of solids, the safest approach in establishing what the back-up pressure behind the casing will be is to assume a water gradient. As mentioned in the first paragraph of Section 1B.6, below the cement top the pore pressure gradient curves from Figure 1-3 can be used as the back-up pressure for the rest of the casing and liners in the string.

The next step is to plot the net differential pressure curve vs depth (shown in red) by subtracting the external pressure data from the internal kick profile curve as shown on Figure 1B-2. The maximum internal pressure at the surface is 6,644 psi with "0" back-up pressure outside the casing, since there is no pressure back-up from mud at a depth of "0" feet at the surface. The pressure inside the casing at 7,500 ft (cement top) is 12,000 psi. The back-up pressure at this depth is 3,250 psi. The difference is 8,750 psi which is plotted on the red net burst curve at 7,500 ft. This process is repeated to produce the rest of the Net Burst Curve as shown. Below 7,500 ft the internal pressure profile curve continues to increase but at a lower rate than above. At the drawn down producing zone from 8,200 ft to 8,500 ft the external pressure is reduced to 4,000 psi, which is below original pore pressure gradient above and below the zone. The lower back-up support increases the net burst slightly across the interval. Below the drawn down zone the back-up pore pressure curve begins to increase at a higher rate toward the protective casing string shoe at 14,500 ft, because this is where the abnormal pressure transition occurs in the well. The internal pressure profile curve for the kick scenario below 7,500 ft continues to increase with depth but at a much slower rate than above because the pressure change with depth is only due to the gas gradient of the bubble when it was on bottom. The result is a reduction in the net burst design requirements from a depth starting below 8.500 ft towards bottom of the protective string as noted on Figure 1B-2.

1B.7 Selecting the casing and liners weight and grades to meet the burst requirements

The last step in designing the protective casing string is to select the weights and grade for the casing and liners to meet the net burst requirements for the string. The performance properties for casing and tubing are available from several sources including pipe manufacturers, service company manuals, API, and from operator literature. The data from these sources is based on the application of API standards. For convenience in cases presented here performance data was obtained from tables available on line from TenarisHydril.

When searching the casing design performance tables it was quickly determine that the highest standard grade and weight of 13 ⅝-in. casing being manufactured is 88.2-lb Q-125 with a burst rating of 10,040 psi. Because this string will be used to drill through the lower part of the well starting from 11,500 ft to TD for many days it is appropriate to apply a wear safety factor of at least 10% as well as an additional safety factor of 1.2 for data variance as recommended in the Byrom book. Applying these safety factors to the burst capacity rating for this casing yields a design pressure rating of 7,530 psi for the strongest pipe available without a special casing mill run to manufacture stronger casing. When the burst rating for the 88.2-lb Q-125 pipe (labeled and shown as a vertical dashed line on the graph) is compared to the design curve on appendix Figure 1B-2 the results indicate that the casing will only meet the burst requirement for the top 2,500 ft and below 9,200 ft for the kick scenario assumed. The protective casing string will be deficient in burst for a major length of the casing in the middle section of the string and no standard mill run higher capacity casing is available.

Below 11,200 ft, where the 10 ¾-in. liner is used, the choice to meet the burst requirements (labeled and shown as a vertical dashed line) for the lower section can be 65.7-lb Q-125 with a rating of 12,100 psi. After an equal derating for wear and the standard safety factor of 1.2, the burst capacity rating for this application would be 9,076 psi which is sufficient to meet the net burst design requirements. The 7 ⅝-in. liner below the 10 ¾-in. liner has an even greater burst rating than the 10 ¾-in. section and is also at a depth where burst requirements are much lower, as indicated by the net burst curve.

One thought that was considered to help increase the pressure capacity through the middle section of the protective casing string design was to extend and hang the higher burst capacity 10 ¾–in. liner higher up into the 13 ⅝–in. casing, to put it behind the stronger pipe. The 10 ¾-in. would handle the pressures that the bigger casing cannot withstand. This idea however turned out to be a very expensive and impractical solution. Hanging the 10 ¾-in. liner higher up into the 13 ⅝-in. casing causes the gas column during the kick scenario, when the gas is on bottom, to be even taller and pressures to be higher than in the base design case. The taller gas bubble also pushes the higher pressure seen in the middle of the string in the base case even closer to the top. The amount of 10 ¾-in. casing required to provide the higher burst capacity would essentially result in setting one protective casing string inside another, to allow drilling the lower section while having to land yet another string in the wellhead. Another possibility to use the architecture design contemplated in this conventional case could be to have a special mill run to manufacture 14-in. OD casing with a heavier wall thickness to maintain the ID needed while still meeting the burst requirements, but this would be very expensive.

1B.8 Is there a better way?

See unconventional architecture design approach discussion for protective casing design near the end of Chapter 1 in Paragraph 1.9 and Appendix 1C for unconventional casing design procedure for the example well.

Appendix 1C: Unconventional protective casing and liners design

1C.1 Discussion

Figure 1-6 in Chapter 1 (Well Architecture Design) contrasts the conventional and unconventional architectural designs for the example well used in the chapter. In the conventional design approach the setting depth for the first protective casing out from under surface casing and, for every casing shoe thereafter, are pushed to the deepest depth allowed by the fracture gradient limit below the last open shoe in each hole section. Generally the first protective casing is very large diameter casing (13 ⅝-in. casing in the conventional case example) that along with subsequent liners that will be set below it, will be used to drill into the deeper and higher abnormal pressured section of the hole. The alternate unconventional design procedure sets the first protective casing shoe prematurely before reaching the start of the high pressure transition zone, as a liner (13 ⅝-in. FJ) hung under the surface casing. Setting this liner results in having a higher fracture gradient than what the surface casing shoe can provide for drilling toward the higher pressure transition zone below. This higher fracture gradient at the 13 ⅝-in. liner shoe permits pushing the next shoe deeper into the pressure transition zone (12,500 ft vs 11,500 ft) than in the conventional design case. At the deeper depth with a higher pore pressure and fracture gradient it is possible to run a slightly smaller diameter protective casing (10 ¾-in.) back to the surface than what would be set in the conventional case. The deeper set protective casing can be smaller than in the conventional case because from below this deeper depth it will be possible to drill to TD without increasing the number of strings that will need to be set to get the well down.

The unconventional design approach basically breaks the protective hole section under surface casing into two separate pressure intervals versus one in the conventional case that utilizes 13 ⅝-in. casing for the protective string. This unconventional approach allows the use of smaller (10 ¾-in.), higher pressure capacity casing to be utilized as the protective casing string, to drill the highest pressured section of the hole to total depth where the highest strength capacity 13 ⅝-in. casing manufactured would not meet the pressure requirements to drill through the same interval.

The kick design criteria approach used for drilling the two sections of protective hole intervals in the unconventional design case will be the same as the criteria used in the conventional design case.

1C.1.2 Casing design for the first protective casing interval

The first protective casing string in the unconventional design approach is composed of 16-in. surface casing set at 3,000 ft and a 13 ⅝-in. flush joint liner hung below it from 2,700 to 9,000 ft, just past the drawn down producing zone located between 8,200 and 8,500 ft. Note that independent of whether the drawndown zone would exist, setting a liner at 9,000 ft to gain the added fracture gradient capacity to drill deeper into the transition zone, is still a good choice to achieve a better well design in this example (Ref Figure 1-6). This string will be used to drill into the upper part of the higher pressure transition zone down to 12,500 ft. The kick scenario for the design of the first protective casing set down to 9,000 ft, assumes that a ½ ppg kick occurs while drilling with 13.7 ppg mud near the expected next casing point at 12,500 ft. The well is shut-in and the gas rises or is circulated to the surface. The high pressure results in fracturing of the shoe at 9,000 ft leaving the top half of the protective string full of gas. (This is the same design scenario used for the protective casing design in the conventional architecture case.) The casing, liner and surface equipment must be designed to contain the pressures resulting from a massive kick occurrence where the fracture gradient of the deepest shoe at 9,000 ft preferentially fails under the high pressure.

1C.2.1 Establishing the pressure profile from the kick

The resulting internal pressures profile for this occurrence as the gas is brought to the surface will be determined by using the gas law equations introduced in Appendix 1B. Appendix 1C Figure 1C-1 will be used to show the pressure profile results for the kick scenario described above, for the unconventional casing architecture shown in Figure 1-6, at various stages in the wellbore as the gas is brought to the surface. Figure 1C-1a shows the kick scenario after the well is shut in, and the well breaks down at the 9,000-ft casing shoe as gas rises, ultimately filling the top half of the casing string above 4,500 ft leaving bypassed mud filling the lower half of the casing.

Case I: Calculate the internal pressure profile when the gas fills the top half of the protective string.

Height of gas bubble (H_{G1}) at surface = 4,500 ft

Step 1: Determine the volume of gas in the well down to 4,500 ft. (5 ½ DP x 16-in. casing) + (5 ½ DP x 13 ⅝-in. casing)

Annular space capacity= (2,700 ft x 20 bbl/100 ft) + [(4,500 ft – 2,700 ft) x 12 bbl/100 ft)] = 756 bbl

Pressure at bottom of the gas bubble (P_B) = frac pressure at shoe – mud gradient from the bottom of bubble to the fractured shoe.

P_B = (14.2 ppg. x 0.052 x 9,000 ft) – [(9,000 ft – 4,500 ft) x 0.052 x 13.7 ppg] = 3,439 psi

Calculate the pressure at the top of the bubble, P_T, using gas law Equation 1B-1

$$P_T = P_B\, e^{\left(\frac{m(h_T - h_B)}{ZR\,T_{ave}}\right)} \qquad \textbf{Equation 1B-1}$$

P_B = 3,439 psi at 4,500 ft

$$\text{Gas Grad (GG)} = \frac{P_B - P_T}{\text{Height of gas}}$$

P_T = Pressure at top of gas column
P_B = Pressure at bottom of gas column
h_T = Depth top of gas column, surface: 0
h_B = Depth bottom of gas column = 4,500 ft
H_{G1} = Height of gas, ft = $(h_B - h_T)$
Z = 1
$R = 1{,}544\ \frac{\text{lb ft}}{\text{mole °R}}$ conv. factor oil field unit

m = Molecular mass of methane = 16 lb/mole

T_{avg} = Avg temp gas column °R $\frac{°F}{100\text{ ft}}$
Temp Grad (given) = 80 + 1.5

$$T_{avg} = 80 + \left(\frac{1.5\ °F}{100\text{ ft}} \times \frac{4{,}500\text{ ft}}{2}\right) + 460 = 573\ °R$$

$$P_T = 3{,}439\, e^{\left(\frac{16\,(0 - 4{,}500)}{1 \times 1{,}544 \times 573}\right)}$$

P_T = 3,170 psi, top of the gas

$$(GG) = \frac{3{,}439 - 3{,}170}{100\text{ ft}} = 0.059\text{ psi/ft}$$

P_{frac} = 14.2 ppg x 0.052 x 9,000 ft
= 6,645 psi at 9,000 ft

Plot pressure profile for Case I with gas bubble at the top as shown on Appendix C, Figure 1C-1.

Data summary for Case I is listed on the bottom of Figure 1C-1a.

Case II: Calculate the pressure profile with the bottom of the bubble at the 13 ⅝-in. liner shoe.

This is a trial and error problem where first an estimate must be made of the size of the bubble when it was on bottom to determine the average temperature and pressure at the midpoint of the gas bubble. These estimated values are then used to calculate what the volume of the gas would be under these downhole conditions using gas law Equation 1B-2. The calculated gas volume is then compared to the estimate made of bubble size used to calculate the average temperature and pressure of the gas column. If the gas volume estimate closely compares to the calculated volume from gas law Equation 1B-2, this means that the estimate was fairly accurate and that it can be used to determine pressures at the top and bottom of the bubble. This data can then be used to build the profile curve for when the bubble had risen to just above the shoe of the 13 ⅝-in. casing. If the gas volume calculated using the equation is not close to the estimate, then a new estimate must be made and tried to close-in on the right volume.

The gas influx volume is known to be 756 bbl when it reached the surface in Case I. A good first assumption is to estimate that the gas volume (V_2) was compressed down to about 60% of the surface volume (V_1) when it was under downhole pressure and temperature conditions just above the liner shoe.

V_2 = 0.60 x 756 bbl

V_2 = 450 bbl

Refer to Appendix 1C Figure 1C-1b.

Bubble height (H_{G2}) will occupy the annulus between 5 ½-in. DP and 13 ⅝-in. liner just above the shoe. Annular capacity is 12 bbl/100 ft:

Bubble height (H_{G2}) = 450 bbl x 100 ft/12 bbl = 3,750 ft

Top of bubble = 9,000 ft – 3,750 ft = 5,250 ft

Calculate gas volume (V_2) under downhole conditions by using Equation 1B-2 and known volume of gas (V1) under conditions when gas is at the surface.

$$P_1 V_1 T_2 = P_2 V_2 T_1 \qquad \textbf{Equation 1B-2}$$

Rearrange Equation to solve for V_2 , $V_2 = P_1V_1T_2/P_2T_1$

Assume Gas Gradient = 0.07 psi/ft at higher downhole pressure above shoe

P_{1avg} & T_{1avg} can be estimated at midpoint of the gas column when gas is at the surface

P_{1avg} = 3,170 psi + (0.059 psi/ft) x (4,500 ft/2)
P_{1avg} = 3,305 psi
V_1 = 756 bbl
T_{1avg} = 80 + (1.5/100) x (4,500 ft/2) + 460 = 573°R

$P_{2avg} = P_{frac}$ – GG x (height to midpoint of gas bubble)
Depth to midpoint = 9,000 ft – 3,750 ft/2 = 7,125 ft

For the gas H_{G2} downhole conditions, use the following:
P_{frac}= 6,645 psi (pressure at shoe, base of the bubble)
P_{2avg} = 6,645 psi – 0.07 x (9,000 ft – 7,125 ft)
P_{2avg} = 6,513 psi
T_{2avg} = 80 + ((1.5°F/100 ft) x 7,125 ft) + 460 = 646°R

Use rearranged Equation 1B-2 to solve for V_2:

$$V_2 = \frac{P_1 V_1 T_2}{P_2 T_1} = \frac{3,305 \times 756 \times 646}{6,513 \times 573} = 433 \text{ bbl}$$

Assumed 450 bbl. This is a close enough estimate.

Use calculated bubble volume of 433 bbl to calculate bubble height:

Bubble height (H_{G2}) = 433 bbl x (100 ft/12 bbl) = 3,608 ft

Top of the gas bubble (h_T) = shoe depth (h_B) – bubble height = 9,000 ft – 3,608 ft = 5,392 ft

Use calculated V_2 (433 bbl) data in gas law Equation 1B-1 to calculate P_T of the bubble.

With base of the bubble at the shoe (h_B), P_B is frac pressure at the shoe and equals 6,645 psi.

$$P_T = P_B\, e^{\left(\frac{m(h_T - h_B)}{ZR\, T_{ave}}\right)}$$

$$P_T = 6,645\, e^{\left(\frac{16\,(5,392 - 9,000)}{1 \times 1,544 \times 646}\right)}$$

P_T = 6,271 psi at 5,375 ft
P_B = 6,645 psi at 9,000 ft
Pressure at the surface is equal to pressure at the top of the bubble – mud head above the top of the bubble to the surface.

$P_{surf} = P_T$ – mud gradient × mud height above bubble

P_{surf} = 6,271 psi – 13.7 ppg × 0.052 × 5,392 ft = 2,429 psi

Results of pressure profile data for Case II when gas bubble is just above the casing can now be plotted on Appendix 1C Figure 1C- 1. Data summary for Case 2 is listed at the bottom of Figure 1C- 1b.

Pressure line ABCD on the graph defines the maximum internal pressure profile for the kick scenario assumed in this example.

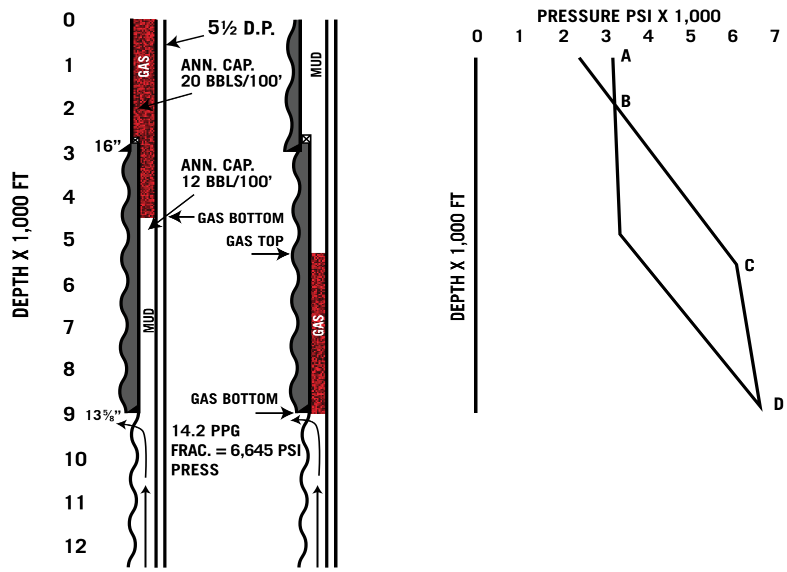


FIGURE 1C-1a

BUBBLE AT TOP
BUBBLE VOL = 756 BBLS
H_{G1} = 4,500 FT
P_{BOTB} = 3,439 PSI @ 4,500 FT
P_{TOPB} = 3,170 PSI "0" FT
P_{FRAC} = 6,645 PSI @ 9,000 FT

FIGURE 1C-1b

BUBBLE AT SHOE
BUBBLE VOL = 433 BBLS
H_{G2} = 3,608 FT
BUBBLE TOP = 5,392 FT
P_{TOP} = 6,271 PSI @ 5,392 FT
P_{BOT} = 6,645 PSI @ 9,000 FT
P_{SURF} = 2,429 PSI "0" FT

Figure 1C-1: Kick pressure profile curves 756-bbl gas bubble at surface formation fractures at 9,000-ft shoe at 14.2 ppg (6,645 psi) (unconventional protective CSG design).

1C.2.2 Establishing the differential pressure design vs depth curve

To design the casing it will be necessary to determine the differential pressure vs depth that will be exerted on the BOPs, wellhead, and the surface casing and liner that make up the first protective casing string. Appendix 1C Figure 1C-2 shows a drawing, on the right, for the surface casing and liner combination protective casing string for drilling below 9,000 ft. The left side of Figure 1C-2 shows a plot of the internal and external pressure design curves that are required to determine the differential pressure vs depth for the casing. Curve ABCD (shown in blue) is a plot of the internal pressure profile for the assumed kick scenario that was calculated in paragraph 1C.2.1 above shown on prior Figure 1C-1. The curve labeled, "pore pressure curve," (shown in green) represents the external pressure gradient for the hole section from the surface to 9,000 ft, which can be obtained from Figure 1-3 in Chapter 1 as a given for the example well case being used.

The next step is to plot the differential pressure design curve vs depth by subtracting the external pressure profile values, from the internal pressure kick profile curve over the entire protective casing and liner length. The maximum internal pressure at the surface is 3,170 psi when the gas reaches the top. The external back-up pressure at the surface is "0" psi, therefore the internal burst design requirement at the surface is 3,170 psi. The internal pressure inside the casing at 5,392 ft is 6,271 psi and the back-up pressure from the pore pressure curve at that depth is 2,700 psi. The differential pressure at 5,392 ft is therefore 3,571 psi. This process is repeated for several depths to produce the net burst design curve (shown in red) which is labeled on the graph. Note that the net burst pressure is reduced toward the bottom where the back-up pore pressure is increasing with depth.

1C.2.3 Selecting the casing weights and grades to meet the design pressures

The last step in completing the design is to select the casing and liner pipe weights and grades needed to meet the pressure requirements for the net burst loads. The performance properties for casing are available in literature published by API, pipe manufacturers, operators and service companies and are based on use of the API standards. For convenience the tables published and available online by TenarisHydril were used for this design example.

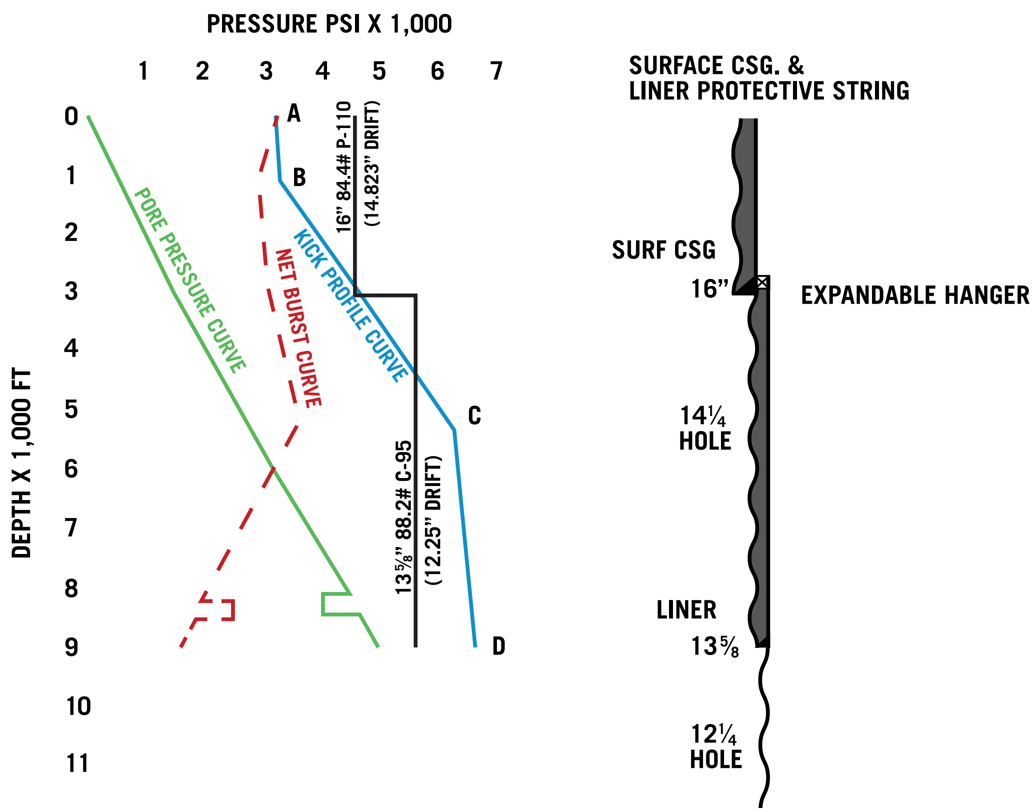


Figure 1C-2: Protective casing & liners design for max kick/differential pressure worst case 756-bbl kick at surf./frac at last shoe (unconventional architecture design)

The results of the search indicate that 16-in., 84.8-lb P-110 (14.823-in. drift ID) casing with a burst rating of 6,020 psi will meet the requirements for the upper part of the protective casing (also serves as surface casing) for this string. This casing will allow drilling a 14 ¾-in. hole to accommodate the 13 ⅝-in. flush joint liner and expandable hanger that will hang inside the lower end of the surface casing to complete the first protective string to 9,000 ft. (The 14 ¾-in. hole can be enlarged to provide more room for cementing if hole conditions should require it.) Because this casing string will be used to drill through to reach the deeper transition zone it will be necessary to derate the burst capacity by 10% for wear, and also to use an additional 1.2 safety factor for other possible design load variables. This yields a design burst rating of 4,515 psi. Still referring to Appendix 1C Figure 1C-2, note the vertical annotated line representing the burst rating of the 16-in. casing exceeds the net burst curve requirements for the design. The 13 ⅝-in. liner run below the 16-in. casing selected form the performance property tables will be 88.2-lb, C-95 casing with flush joint connections. This casing has a burst rating of 7,630 psi. Because this liner serves as the surface casing string extension to complete the protective string which will be used to drill into the deeper transition zone, it should also be derated in its burst capacity by 10% for drillpipe rotation wear. In addition a safety factor of 1.2 should also be applied to account for any unknown design load variables. Using these safety factors will then yield a net burst rating of 5,722 psi. The selection of 13 ⅝-in., 88.2-lb (12.25-in. drift ID) casing for this liner will allow drilling a 12 ¼-in. hole below this protective string to provide the ID clearance required for the connections on the 10 ¾-in. protective casing, which will be set at the next casing point and landed at the surface. The derated design burst capacity of this 13 ⅝-in. liner in comparison to the net burst requirements is also shown and annotated as a vertical line on Figure 1C-2.

1C.3 Designing the protective casing string to be set at 12,500 ft

Figure 1-6 in Chapter 1 for the unconventional design case shows that the next casing shoe below 9,000 ft will be reached at a depth of 12,500 ft as drilling mud weight approaches the fracture margin limit at the 13 ⅝-in. liner shoe above at 9,000 ft. At this depth the plan is to set a full string of 10 ¾-in. casing to the surface to provide the burst capacity required to drill the well to TD. Drilling to total depth will however require setting a 7 ⅝-in. FJ liner below the 10 ¾-in. casing shoe to about 14,500 ft, where the drilling mud weight of 15.7 ppg will be at the margin fracture gradient at 12,500 ft where the 10 ¾-in. casing shoe was set. (See the vertical 15.7 ppg mud weight/fracture gradient line on Figure 1-6 between 14,500 ft and 12,500 ft) The 10 ¾-in. casing and the 7 ⅝-in. liner hung below it to 14,500 ft will serve as the protective casing string to drill the well to TD and will also put the potential lost returns zone above 14,500 ft depth behind pipe. (In the ideal case the drift ID of the 10 ¾-in. casing will need to be at least 9 ¼ in. to allow drilling a hole that will provide extra clearance and reduced surge pressures to run and cement the 7 ⅝-in. liner across the potential loss zone.) The 7 ⅝-in. liner portion of this combination protective string will be tied back to the surface and be used in production service as the middle section of the production casing later when the well is completed. This 7 ⅝–in. liner can be exactly the same combination protective/production liner that was designed in the production design case in Appendix 1A in the conventional case. This is because the well conditions for the intended production service are the same. This is also true because the casing design criteria for the 7 ⅝-in. liner in production service are much more stringent than the requirements under protective casing service as the design curves will show.

1C.3.1 Establishing the burst curves for the protective casing string design

The burst design criteria scenario for the protective casing string made up of the 10 ¾-in. casing and 7 ⅝-in. liner for drilling the well to TD and through the prospective production interval, will be the same as for the protective casing string used to drill to TD in the conventional case in Appendix 1B.

Figure 1C-3 shows the proposed casing and liner protective string set at 14,500 ft on the left side. The protective casing design criteria for drilling to TD and through the production interval assumes, as before, that a massive influx of gas occurs while drilling near TD with 16 ppg mud in the hole. The well is shut in and as the gas rises it fractures the shoe at 14,500 ft. When the gas reaches the surface the top half of the protective casing string down to 7,250 ft is full of gas and mud fills the remainder of the casing below the gas down to and below the 7 ⅝-in. liner shoe. The fracture pressure of the shoe, P_{frac}, at 14,500 ft is 18 ppg or 13,572 psi. The surface equipment in the well and the protective casing string composed of the 10 ¾-in. casing and 7 ⅝-in. liner will be designed to be stronger than the resulting pressure profile which fractures the shoe.

The first step in determining the burst pressure design values for the protective casing string that occur from the kick scenario described above is to use the gas law equations introduced in Appendix 1B to calculate the pressure profile that results as the gas influx migrates or is circulated out of the well. Figure 1C-3 will be used to show the kick profile results for the gas influx scenario when the gas reaches the top of the well, and when the gas was just above the shoe of the protective casing string. These two cases will define the highest internal pressure profile curve for the design kick scenario described above.

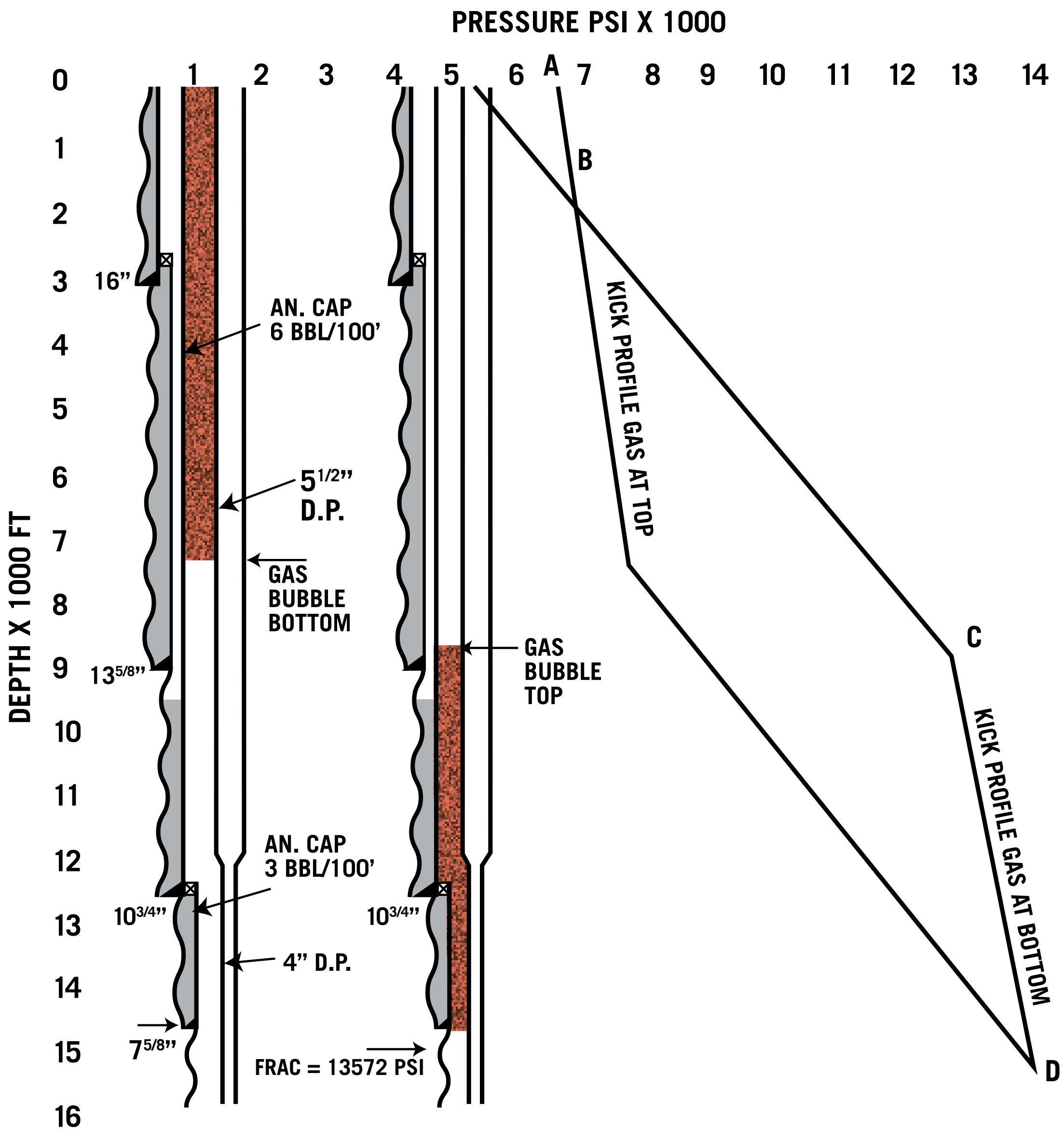


FIGURE 1C-3a

CASE I
GAS AT TOP
VOL = 435 BBLS
H_{G1} = 7250 FT
SSIP = 6644 PSI
$P_{BOT\ GAS}$ = 7540 PSI
P_{FRAC} = 13572 @ 14500 FT

FIGURE 1C-3b

CASE II
GAS AT BOTTOM
VOL = 284 BBLS
H_{G2} = 5883 FT
SSIP = 5290PSI
TOP GAS = 8617 FT
$P_{TOP\ GAS}$ = 12459 PSI
P_{FRAC} = 13572 PSI @ 14500 FT

Figure 1C-3: Kick pressure profile curves for 435 gas bubble at surface. Formation fractures at 14,500 ft shoe at 13,572 psi (18 ppg equivalent) (unconventional architecture design).

Case I: The gas fills the top half of the casing string (Figure 1C-3a).

The first step in calculating the pressure profile is to determine the volume of gas that occupies the top of the casing down to a depth of 7,250 ft (h_B). The annular capacity between the 5 ½-in. drillpipe and the 10 ¾-in. casing at the top is given as 6 bbl/100 ft. The volume of gas is: V_1 = 7,250 ft x 6 bbl/100 ft = 435 bbl.

The pressure at the bottom of the gas column (P_B) is equal to the fracture pressure at the shoe minus the hydrostatic head of the mud from the shoe to the bottom of the gas bubble at 7,250 ft.

P_B = 13,572 psi – (16 ppg x 0.052 x 7,250 ft) = 7,540 psi

Using the gas law Equation 1B-1 calculate the pressure (P_T) at the top of the gas bubble (h_T), at "0" ft (surface):

$$P_T = P_B\, e^{\left(\frac{m(h_T - h_B)}{ZR\,T_{ave}}\right)}$$

$P_{T\,(surface)}$ = Unknown
P_B = 7,540 psi
h_T = "0" depth to top of bubble
h_B = 7,250 ft depth to bottom of bubble
H_{G1} = Height of gas, ft = (h_B – h_T)
Z = 1
$R = 1{,}544\ \dfrac{\text{lb ft}}{\text{mole °R}}$ (conv. factor oil field unit)

m = Molecular mass of methane = 16 lb/mole
T_{avg} = Avg temp gas column °R
Temp Grad (given) = $1.5\ \dfrac{\text{°F}}{\text{100 ft}}$

Surface temperature = 80°F

$$T_{avg} = 80 + \left(\frac{1.5\ \text{°F}}{100\ \text{ft}}\ \text{X}\ \frac{7{,}250\ \text{ft}}{2}\right) + 460 = 594\text{°R}$$

$$P_T = 7{,}540\, e^{\left(\frac{16\,(0 - 7{,}250)}{1 \times 1{,}544 \times 594}\right)}$$

P_T = 6,644 psi

$$\text{Gas grad (GG)} = \frac{7{,}540 - 6{,}644}{7{,}250} = 0.124\ \text{psi/ft}$$

P_T = 6,644 psi at "0" ft
P_B = 7,540 psi at 7,250 ft
P_{frac} = 13,572 at 14,500 ft

Plot the pressure profile data for gas at surface on Figure 1C-3. Data summary for Case I is shown at base of Figure 1C-3a.

Case II: Calculate the pressure profile data for the well when the gas column is on bottom just above the shoe of protective casing string (14,500 ft) (Figure 1C-3b).

As described in prior problem examples, this is an iterative trial and error process that first requires an estimate of what the known volume of the gas, (V_1), (435 bbl)when it reaches the top of the casing, was compressed to, (V_2), when it was under downhole conditions just above the casing shoe at 14,500 ft. The estimated volume, V_2, is then used to calculate what the average temperature and pressure in the gas column above the shoe would be under downhole conditions. The estimated average temperature and pressure values are then used in Ideal gas law Equation 1B-2 to calculate V_2. The calculated gas volume is then compared to the estimate made of the bubble size used to calculate the average temperature and pressure of the gas column. If the gas volume estimate closely compares to the calculated volume from the gas law Equation 1B-2, this means that the estimate was fairly accurate and can be used to determine pressures at the top and bottom of the bubble under downhole conditions.

Make an estimate of V_2 under downhole conditions and calculate V_2 using Equation 1B-2.

Ideal gas law Equation 1B-2, $P_1V_1T_2 = P_2V_2T_1$

Rearrange equation to solve for V_2, $V_2 = P_1V_1T_2/P_2T_1$

V_1 = Volume of gas when bubble was at the surface is 435 bbl. Assume as a first estimate that gas volume under downhole conditions, V_2, will be 60% of V_1, V_2 = 0.6 x 435bbl = 261 bbl

Also known from Case I, gas gradient (GG) = 0.124 psi/ft

Calculate average pressure of gas column for V_1 at midpoint.
$P_{1avg} = P_T$ + GG x column height/2

P_{1avg} = 6,644 psi + 0.124 psi/ft x 7,250 ft/2 = 7,093 psi

T_{1avg} = 594°R

Calculate gas column height (H_{G2}) when the bottom of the gas bubble is at the 7 ⅝-in. casing shoe. (Ref. Figure 1C-3b.)

Annular capacity of the 4-in. drillpipe in the 7 ⅝-in. liner:

(14,500 – 12,200 ft) = 3 bbl/100 ft × (14,500 - 12,200 ft) = 69 bbl

The balance of the 261 bbl of gas bubble is above top of the 7 ⅝-in. liner at 12,200 ft: (261 bbl – 69 bbl) = 192 bbl

The bubble height above liner top in annulus of 5 ½-in. DP × 10 ¾-in. casing = 192 bbl × 100 ft/6 bbl = 3,200 ft

Total height of gas column is the height occupied between 14,500 – 12,200 ft, (14,500 ft – 12,200 ft = 2,300 ft), plus the height of the remaining gas above the top of the liner at 12,200 ft (3,200 ft). Total gas column height = 2,300 ft + 3,200 ft = 5,500 ft. The top of the gas column is 5,500 ft above the 7 ⅝-in. liner shoe. Top of gas column = 14,500 ft – 5,500 ft = 9,000 ft.

To calculate P_{2avg} and T_{2avg}, (pressure and temperature at midpoint of gas column height), when the bottom of the gas bubble is just above the shoe at 14,500 ft requires estimating a gas gradient for the column under downhole conditions above the shoe. Use an estimated gas gradient at 0.17 psi/ft at higher pressure vs 0.124 psi/ft for the gas at the surface in Case I.

$$P_{2avg} = \text{BHP} - \frac{\text{Gas Grad x Height}}{2}$$

P_{2avg} is pressure at midpoint of the bubble. BHP at shoe is equal to frac pressure = 13,572 psi:

$$P_{2avg} = 13{,}572 - \frac{0.17 \text{ x } 5{,}500}{2} = 13{,}104 \text{ psi}$$

Calculate T_{2avg}, Temp at midpoint of the bubble:

$$T_{2avg} = 80 + 1.5 \ \frac{°F}{100 \text{ ft}} \left(14{,}500 \text{ ft x } \frac{5{,}500}{2}\right) + 460 = 716°R$$

Calculate V_2:

Rearrange Gas law Equation 1B-2 to solve for V_2:

$$V_2 = \frac{P_1 V_1 T_1}{P_2 T_1} = \frac{7{,}093 \text{ x } 435 \text{ x } 716}{13{,}104 \text{ x } 594} = 284 \text{ bbl}$$

Calculated V_2 = 284 bbl vs estimate of 261 bbl

This is close enough, because the estimated value for the volume of gas on bottom is only used to calculate the column height which is then used to calculate the average temperature and pressure at the midpoint of the column. (T_{2avg} and P_{2avg}) Trying a new volume closer to the 284 bbl would only change T_{2avg} a few degrees and P_{2avg} a few psi since the temperature gradient is only 1.5°F/100 ft and the gas gradient is only 0.17 psi/ft.

Using the calculated value for V_2, now calculate the height of the gas column on bottom. The capacity of the annular space between the 4-in. DP and the 7 ⅝-in. casing from 14,500-12,200 ft is 69 bbl, as calculated above. The balance of the 284 bbl of gas when the bubble is on bottom is above 12,200 ft, which is then 284 bbls – 69 bbl = 215 bbl. The height of the gas above 12,200 ft is then 215 bbl divided by the annular capacity between the 5 ½-in. DP and the 10 ¾-in. casing. The annular capacity for this section is 6 bbl/100 ft so the gas height of 215 bbl is 215 bbl x 100 ft/6 bbl = 3,583 ft.

The total bubble height = 2,300 ft + 3,583 ft = 5,883 ft

The top of the gas is at 14,500 ft – 5,883 ft = 8,617 ft

Using the ideal gas law Equation 1B-1 now find the pressure profile for the column of gas and mud when the gas bubble is above the shoe.

Ideal gas law Equation 1B-1:

$$P_T = P_B \, e^{\left(\frac{m(h_T - h_B)}{ZR\,T_{ave}}\right)}$$

P_B = 13,572 psi, frac pressure at shoe
h_T = 8,617 ft depth to the top of gas bubble
h_B = 14,500 ft depth to the bottom of gas bubble
H_{G2} = Height of gas, ft = ($h_B - h_T$) = 5,883 ft
Z = 1
m = Molecular mass of methane = 16 lb/mole
T_{avg} = Avg temp gas column °R

Temp Grad (given) = 80 + 1.5

$$T_{avg} = 80 + \frac{1.5\ °F}{100 \text{ ft}} \text{ x } \left(14{,}500 - \frac{5{,}883 \text{ ft}}{2}\right) + 460 = 713°R$$

$$P_T = 13{,}572 \, e^{\left(\frac{16\,(8{,}617 - 14{,}500)}{1 \text{ x } 1{,}544 \text{ x } 713}\right)}$$

P_T = 12,459 psi, top of the gas

$$\text{Gas Grad} = \frac{P_B - P_T}{\text{Height of gas}} = \frac{13{,}572 - 12{,}459}{5{,}883}$$

Gas Grad = 0.189 psi/ft

Surface shut-in pressure = Bottom hole fracture pressure – gas head – mud head to casing shoe.

SSIP = 5,290 psi at surface, "0" ft
P_T (top of gas bubble) = 12,459 psi at 8,617 ft
P_{frac} (bottom of gas bubble at shoe) = 13,572 psi at 14,500 ft

Using these values, the pressure profile curve for the gas bubble above the shoe are plotted on Appendix C, Figure 1C-3b.

Curve ABCD represent the maximum internal pressure profile curve for the kick scenario assumed for the deep protective casing string in this example.

1C.3.2 Establishing the differential pressure vs depth design curve

The next step toward designing the protective casing string is determining the differential burst pressure that will be exerted on the casing and liner from the kick scenario completed above. Appendix 1C Figure 1C-4 shows the protective casing (10 ¾ in.) and liner (7 ⅝ in.) configuration set at 14,500 ft that will be used to drill to TD. On the left side are a series of internal and external pressure curves that will be used to determine the differential pressure vs depth for the casing to meet the assumed kick design criteria. Curve ABCD (shown in blue) is a plot of the internal pressure for the assumed kick scenario calculated above in 1C.3.1 and shown previously on Figure 1C-3. The curve labeled “External Back-Up Pressure Curve” (shown in green) represents the behind-pipe pressure gradient (for design purposes), which assumes that a water gradient exists above the shoe where the 13 ⅝-in. casing was set at 9,000 ft. Below the 13 ⅝-in. casing, the assumption is that pore pressure backs up the 10 ¾-in. and 7 ⅝-in. protective casing string down to 14,500 ft. The pore pressure data is obtained from Figure 1-6 in Chapter 1. The assumption of a water gradient on the annulus between the 10 ¾-in. and 13 ⅝-in. casings down to the setting depth of the 13 ⅝-in. casing shoe is very conservative, because the 10 ¾-in. casing was cemented with 13.7 ppg mud in the hole. However, because there is no way to establish how far the solids in the mud may have settled over time, which would leave very light fluid or even water in the upper part of the 10 ¾-in. by 13 ⅝-in. annulus, this assumption ensures that the casing can withstand the design pressure for the entire string, especially in the upper portion, regardless of how much mud solids settling occurs. The back-up pressure below the shoe of the 13 ⅝ in. (9,000 ft) and the bottom of the protective casing string at 14,500 ft is assumed to be no less than the pore pressure of the formations. Subtracting the external back-up pressure values from the internal burst curve values generated by the kick at various depths over the length of the string will produce the differential pressure design curve that will be used to select casing weights and grades to meet the burst requirement. (See annotated differential pressure design curve, shown in red, on Appendix 1C Figure 1C-4). The differential burst pressure at the surface is equal to the internal burst pressure of 6,644 psi, because there is no back-up pressure at the top of the annulus. The maximum differential design pressure occurs between 8,600 ft and 9,000 ft and then decreases below as the backup pore pressure increases with depth. At 8,617 ft the maximum kick profile pressure is 12,459 psi and the external back-up pressure on the casing at 8,617 ft for a water gradient is 3,732 psi. The difference is 8,726 psi which is the net burst design pressure at the highest point.

1C.3.3 Selecting the casing weights and grades to meet the design loads

The last step in designing the casing string is to use performance property curves, available from various sources, to select the casing weights and grades to meet the burst load requirements of the differential pressure curve in Appendix 1C Figure 1C-4. As in previous examples, the TenarisHydril website performance tables available on line will be used for tubular performance properties data and materials selection. To meet the burst requirements, starting at the top, 10 ¾-in., 71.1-lb C-95 (9.294-in. drift ID) casing with a burst rating of 10,050 psi is selected. After reducing the rating by 10% for wear, because downhole drilling will be done through this string, using a design safety factor of 1.2 for data variation yields a design burst rating of 7,537 psi. This casing can be used from the surface down to about 5,600 ft where it will meet the burst requirements. (See vertical dashed line representing the 7,537-psi design burst pressure rating for the casing selected on Appendix 1C Figure 1C-4 intersecting the differential pressure curve at 5,600 ft.) Below this depth the pressure requirements increase and stronger casing with a higher burst capacity is required. Using performance properties data next select 10 ¾-in. 71.1-lb P-110 (9.294-in. drift ID) casing with a burst capacity rating of 11,640 psi. After reducing the rating by 10% for drilling wear, and using a 1.2 design safety factor for data variances, a design burst rating of 8,730 psi can be used for this casing. Again referring to Appendix 1C Figure 1C-4, note the vertical dashed line representing the design burst rating for this 71.1-lb P-110 pipe selection. This casing will meet the burst requirements for the remainder of the design down to the end of the 10 ¾-in. section of the string. To provide the string’s required connection strength while also allowing the needed clearance to run this casing through the 13 ⅝-in. liner and the 12 ¼-in. open hole, select the Hydril MACII connections with 11.1-in. OD, and a tensile capacity exceeding 2 million pounds. Buttress connections can also be used in the top 2,500 ft if desired, where the 10 ¾-in. casing will be inside the 16-in. surface casing and clearance is not an issue. If the designer wishes, a change back to the lower burst capacity C-95 casing, used at the top, can also be substituted below 9,500 ft, where the burst requirements once again will be reduced as shown on the design curve. The designer must consider the potential savings vs the trouble and potential risk associated with keeping the right order for when running a mixed grades and weights casing string.

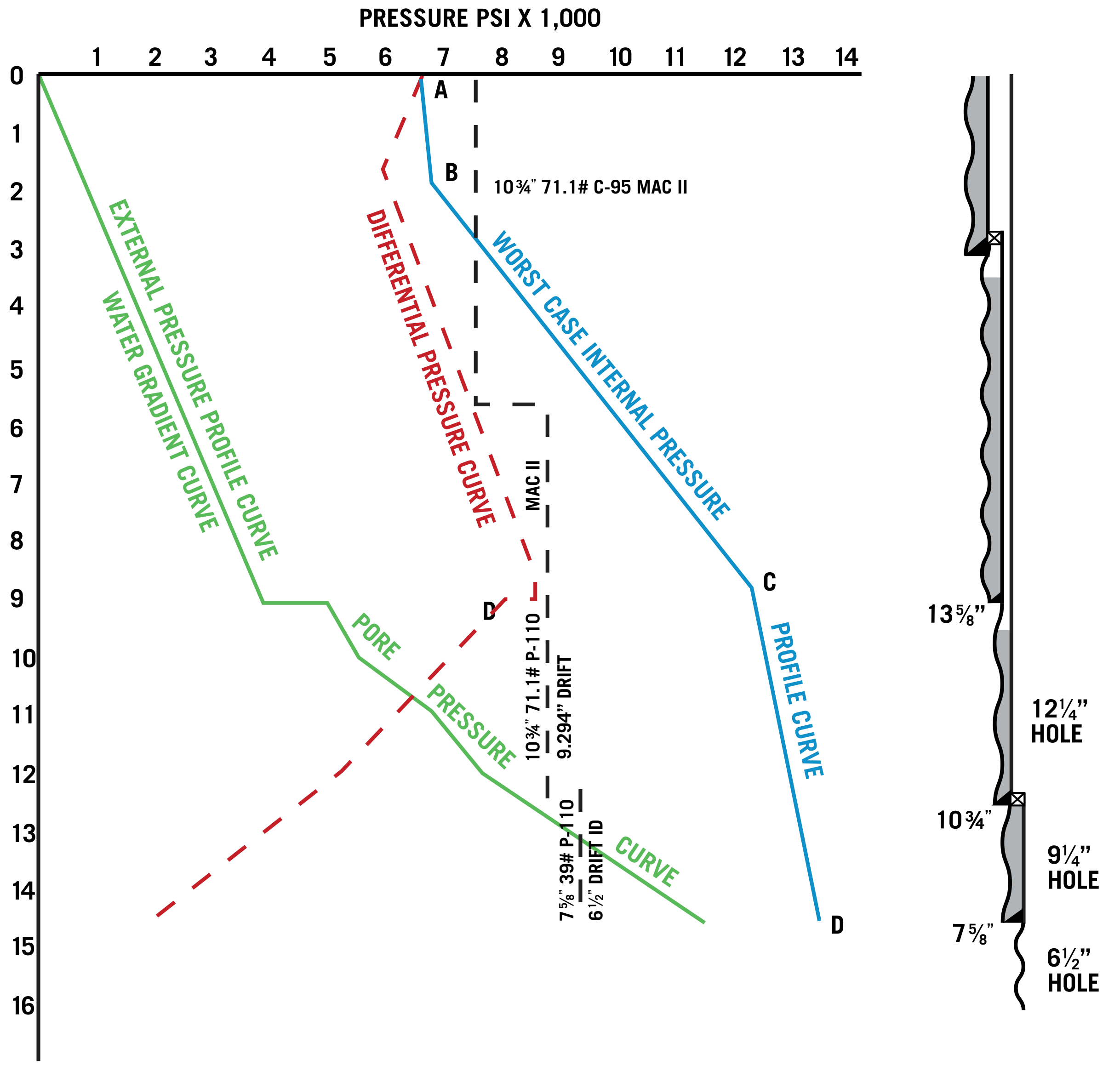


Figure 1C-4: 10 ¾-in. x 7 ⅝-in. protective casing & liner design, max kick differential pressure worst case top half of well full of gas. frac. relief at last liner shoe @ 14,500 ft (13,572 psi, 18 ppg) (unconventional architecture design).

The vertical annotated line showing the burst capacity for the lower portion of the protective casing string is for the 7 ⅝-in., 39-lb P-110 FJ liner selected earlier in the production casing design in Figure 1A-2. The high burst rating for the 7 ⅝-in. liner is governed by the production case. The burst design rating assumes a 10% wear and 1.2 safety factor for this liner also, because it will be part of the protective casing string to drill the well to TD.

Authors' note

New products have come on the market to meet the challenges of today's higher-standard regulatory environment and deeper, higher-pressure well prospects. In the example well discussed above, using the 10 ¾-in. x 7 ⅝-in. protective string to drill to TD for the unconventional design, the operator could opt to design the protective string to withstand full well shut-in pressure with the well full of gas if desired or required. This can be accomplished by using the now easily available standard 10 ¾-in., 79.9-lb Q-125 casing from the surface to 9,500 ft in place of the 71.1-lb P-110 used in the above design. The 79.9-lb Q-125 casing has a burst pressure rating of 16,130 psi. The special drift casing would still allow drilling a 9 ¼-in. hole to set the 7 ⅝-in. liner below it.

The maximum shut-in differential pressure for the example well case full of gas to the top would be 11,710 psi at the surface and would drop to 8,730 psi at 9,500 ft. Below 9,500 ft, the differential pressure would be further reduced towards

TD. The 10 ¾-in., 79.9-lb Q125 casing is rated at 12,100 psi with a 10% wear derating and a 1.2 safety factor for data variations. This design capability could not be matched using the 13 ⅝-in. casing in the conventional design.

Employing an effective wear management program for drilling through the 10 ¾-in. x 7 ⅝-in. protective string and conducting a caliper survey to verify string integrity would allow for the use of this string as the final production casing. This would eliminate the need to run a 7 ⅝-in. production tieback from the top of the combination service 7 ⅝-in. liner below the 10 ¾-in. long string back to the surface to complete the well. Using these new available tubular products would reduce both the complexity of the operations and cost. The design capability using this approach cannot be matched using the 13 ⅝-in. casing as part of the protective string in the conventional design presented in the first part of Chapter 1.

Chapter 2
Well Construction Design

TABLE OF CONTENTS

2.1 INTRODUCTION

As the well architecture design is being developed, the design engineer also needs to formulate a well construction design plan. Put simply, a well construction design plan involves the determination of how each section of hole should be cased (casing vs liner) and the procedures required to achieve the desired section and drill-ahead objectives. The various well section examples used in this chapter on well construction represent scenarios that typically arise when drilling a deep abnormal pressure vertical or low angle directional well similar to the case used in Chapter 1 on well architecture design. The well section and overall construction plan design should be driven by formation isolation requirements, cement job quality needs, well control capability during all operations and a balanced look at cost benefit vs risk for alternative options.

2.1.1 Formation isolation requirements

Wellbore conditions and the need for isolation of freshwater zones and/or possible cross flow communication between zones left behind pipe are important considerations in deciding how a well should be cased and cemented. The final choice is ultimately driven both by a need to meet regulatory requirements to avoid potential contamination of freshwater sources and/or communication between formations of different pressures or with producing zones. Drill-ahead plans and anticipated mud weights will also help define the needs placed on casing and/or liner shoe integrity and/or liner top sealing requirements. Potential for annular flow of formation fluids, primarily gas, following a cement job can also play a significant role in deciding how a well should be cased and cemented especially in cases when a closed or inaccessible annulus is left behind pipe.

2.1.2 Cement quality requirements

Cement job quality will first be determined by how well the mud behind pipe can be replaced with good, clean cement. Isolation requirements, as described in the previous paragraph, cannot be achieved if all or most of the mud is not removed ahead of the cement. Mud will contaminate the cement slurry and leave channels through the cement left in the annulus. The consequence of leaving unset contaminated cement and channels of contaminated clabbered mud is that they provide passage ways for fluid to communicate between formations. These conditions can also negate achieving barriers needed to isolate the cemented section from the hole above the cement top and below the shoe.

2.1.3 Well control capability

Another very important consideration in selecting the well construction design and associated procedures is the ability to manage well control risks while running the pipe, while cementing, waiting on cement and when testing the cement job. Well control considerations when making a casing vs liner decision should include a look at surge and swab pressures that are generated while running the strings. Special emphasis should be placed on how to minimize them where the open formations have low integrity and where there is only a small overbalance of mud head on the highest open formation in the section. The surge pressures generated by a long string vs a liner and drillpipe string and the length of time that it will take to run the pipe to bottom also need to be taken into consideration when making the decision.

Surge pressures while running pipe in the hole are mostly generated by the pressure drop in the annular space between the casing and hole caused by the fluid's resistance to flow and from drag of the fluid moving against the casing and hole walls as it is being displaced up the hole by the pipe each time it is lowered into the well. The parameters that drive pressure drop are the fluid properties, the space in the annulus and the velocity of the moving fluid. Running a liner instead of a full string of casing can be a good way to reduce the pressure drop in the annulus because the drillpipe used to run the liner displaces less fluid than a full casing string and also results in a bigger annular space for the fluid to move in above the liner.

When pipe is run in the hole, a closed-end float shoe at the bottom of the casing causes the volume of displaced fluid to be equal to the total of both the volume of steel that makes up the casing and the internal capacity of the pipe. Using differential fill equipment that also allows the fluids in the hole to enter the casing when the pipe is lowered reduces the volume of fluid being displaced to only the fluid volume equal to the casing displacement. (Example: When lowering casing in the hole the amount of fluid moving up the annulus of an open-ended 7 ⅝-in. casing string and one that is closed is about one quarter as much.) Using differential fill float equipment, where allowed, can reduce the pressure drop in the annulus significantly and can be a good way to help manage surge pressure issues in either the casing or liner choice. (Computer programs are readily available in the industry to calculate pressure surge and swab effects when running or pulling pipe in a well.) Selecting the right type of differential float equipment to fit the well conditions is also very important. Activation to convert the equipment from the filling mode to the shut-off mode should be simple without requiring having to drop sealer balls or darts to make the conversion. If shut-off activation requires pumping, it is important to ensure that the circulating rate required to convert the valves is less than the rate that would cause potential lost returns in the section of hole being circulated. Some equipment is available which can automatically shut-off fluid entry into the casing when a preset in-flow fluid velocity through it reaches a certain limit. This would be the case if, for instance, the well begins to flow while running casing and the BOPs were closed. Shutting in the well would then cause the fluid entry to be forced through the open cementing shoe and float collar up the inside of the casing. Using a combination of fluid entry velocity actuated valves and valves that are activated after pumping through them can provide good flexibility and redundancy in potential lost returns and/or well flow situations. Differential float equipment should not be used in high angle or horizontal wells where there is a danger of plugging the float equipment with cuttings beds that may exist on the low side of the hole where the shoe can be pushed into the bed.

Other safety equipment that should be available on the rig floor during casing and liner running operations would include all appropriate crossovers, valves and inside BOP's needed to quickly stab into the casing or drillpipe being run to facilitate making a connection to pump into the well or to strip drillpipe into the hole if it becomes necessary. Training the crews and having drills to practice installing the safety valves and crossovers to connect to the casing or drillpipe in the rotary should also be done prior to running the casing or liner in the well.

Avoiding a well control situation during the actual cementing operations should also be part of a good job plan, although in most cases it is safe to say that once pipe is in the hole and after mud circulation is started without issues, risks are much reduced. Pipe movement while breaking circulation and slowly initiating pumping or pressuring up on the drillpipe can be an important step to help break up the static mud gels and avoid breaking the well down. Circulating significantly past bottoms up and checking and conditioning the mud before initiating either a casing or liner cement job is a practice that should always be followed without exception. If lost returns should occur when circulating a well, there should be a plan in place to know what to do next. (Fill the back side, reduce circulation rates, pump mud with LCM, etc.) When pumping down the inside of the casing, after losing returns, if the well begins to flow on the annulus make sure that the well is circulating and not coming in because the mud column on the annulus first dropped and an influx has occurred. If gas enters the wellbore from below a loss zone it can swap places with the mud above or cause an underground blowout that will cause the mud and fluids above to also be lost to the zone where the gas is going. Shut the well in if there is any doubt and have a kill procedure in place.

When running a long string, if all goes well and the casing gets to bottom and is then circulated and cemented without incident, does not necessarily mean that well control is no longer of concern. Assuming the plug bumps and the float equipment is working as intended it is still important to be prepared to monitor the casing and casing annulus for flow or losses while waiting on cement. To do this it will be necessary to be rigged up to keep the annulus full and/or to lubricate mud if the well tries to flow. There is no viable way to pressure test a cement job on a long string casing annulus. The only check that can be made is with passive qualitative cement evaluation tools or noise logs that listen for behind pipe fluid movement to test for possible behind pipe cross flow if desired or necessary.

In the case of a liner, where the plan calls for circulating and leaving extra cement above the liner top, after cementing and bumping the plug the drillpipe and setting tools should be pulled up the hole above the cement. (This is normally about 300 ft.) After pulling the drillpipe above the cement, the annulus between the casing and drillpipe should be reversed out completely back to the surface to remove contaminated cement and any cement that may have been dragged up the hole by the setting tools. After completing the reversing process the string should be pulled up an additional 100 ft so the well can then be shut-in with some predetermined pressure, to help monitor the cement job until the cement has set. After waiting on cement the liner can be pressure tested, with the setting tools still in the hole, before pulling out of the hole. This test should be repeated after drilling out the excess cement left on top and inside the top of the liner. On a land well a differential test of the cement placed between the liner and casing annulus below the liner top can be done by running and setting a packer above the liner top with enough tailpipe below it to reach from the top of the liner to the float equipment. The packer can be used to isolate the liner from the mud in the casing above after reducing the hydrostatic pressure below the packer and in the drillpipe. This is accomplished by setting the packer above the liner top, opening the packer bypass and then pumping water down the drillpipe to displace some of the mud out into the annulus and out the top of the well. (This test should be done without pumping any water into the annulus.) The U-tube pressure at the top of the drillpipe will reflect the difference in hydrostatic pressure between the drillpipe and casing side which is still full of kill weight mud both above and below the packer. Closing the bypass and releasing the U-tube pressure at the top of the drillpipe will then leave the reduced hydrostatic pressure in the drillpipe below the packer which will result in a differential test on the liner top and float equipment below. The amount of the differential pressure test below the packer and at the float equipment is equal to the U-tube pressure that was bled off the tubing to initiate the test. On an offshore well a differential pressure test on the liner can also be done with a packer in the same way, or by using the subsea BOPs, like a packer in the land case to do a limited test, to isolate the mud head in the riser above the BOPs from the well below during a similar test. The test would be conducted by running drillpipe to the bottom of the liner to be tested and then pumping water partway down the inside of the drillpipe to a depth where the hydrostatic pressure of the water and the remaining mud column to the end of the drillpipe would be slightly more than the hydrostatic pressure of the mud in the annulus below the BOPs. After closing the BOPs (test rams), closing the choke and kill lines, and bleeding off the drillpipe U-tube pressure at the top of the pipe, the hydrostatic pressure at the bottom end of the drillpipe, both inside and in the annulus, will be reduced by an amount that is equal to hydrostatic head of the mud in the riser above the BOPs. This will test the entire well below the BOPs, but more specifically the liner and cement track below the float equipment to a limited differential pressure equal to the riser head, which has been removed by closing off the BOPs and choke and kill lines, and bleeding the drillpipe U-tube pressure off the top. (See more details on how to conduct these tests, including an example for the subsea case, in Appendix 2A paragraph 2A.1.1, item 9 in the sequence.)

In the case of either a land or deepwater well test, once the differential pressure is placed on the well by releasing the U-tube pressure, and a small flow-back as the pressure is relieved, no further flow-back with the pipe standing full will signifies a good test. Continuous or accelerated flow during this test or pressure build-up after shut-in will signify a leak either at the liner top or at the shoe. The influx can then be shut in and the water can be reversed out from the top of the drillpipe by pumping mud through the kill line below the BOPs and into the annulus between the drillpipe and casing. This operation should be done while holding enough backpressure through a choke at the top of the drillpipe to avoid further entry of fluids from the liner top or float equipment. If a packer was used instead of the BOPs for the test it will be necessary to unseat the packer, after reversing the water out, in order to remove the influx which occurred below the packer. Unseating the packer and reverse circulating the well through the bottom of the tailpipe will remove the influx regardless of whether it occurred at the liner top or through the shoe. After bottoms up, the well can be circulated the long way around until the hole is clean and stable. A repair at that point would involve diagnosing the leak to determine if the float equipment has failed or if the liner top is leaking. After the diagnosis is done the repair may involve squeezing and potentially installing a liner top packer if indicated. Note that in both the land and offshore liner testing procedures described above, water is never placed on the annulus side of the test string and kill weight mud always fills the annulus down to the top of the liner and below (between the tail pipe and the liner) to the float equipment being tested. Essentially this test method allows the use of a kill string in the well during these critical tests which greatly reduces the risk of a well control problem when testing a cement job against a potential high flow capacity zone.

2.1.4 Cost benefit vs risk considerations

The final and most important consideration in making a decision on how a section of hole ought to be cased should be based on an evaluation of cost benefit vs risk between the options available. The cost and risks associated with running and cementing a long string vs a liner are different and will be highly dependent on wellbore conditions. Most choices, from a mechanical perspective, are self-evident with respect to whether the existing casing in a well must be overlapped with a whole new string or just a liner. Generally a full string to the surface must be run when it is necessary to cover an existing string of pipe that lacks the burst or possibly collapse capacity to allow drilling ahead with the anticipated higher or lower fluid densities required. In these cases there is no choice but to run a full casing string or a liner with a tieback if necessary. Liners without a tieback are most frequently used to extend an existing protective casing string to cover formations below the shoe that have lower than the needed fracture gradient to allow deeper drilling. Using a liner extension below a casing string to drill deeper into a pressured section requires that the casing above have the design capacity to withstand the higher anticipated pressures and mud weight to drill ahead. Running a liner in these cases costs less than running a full string and also allows keeping the bigger diameter casing above the liner top so that larger diameter drillpipe can still be used in the upper part of the drillstring to facilitate drilling deeper. Beyond these obvious mechanical drivers, making the final decision on whether to run a liner or full string should be driven by a comparison between the options related to meeting well objectives and well control capability. The decision requires that a realistic assessment of risks associated with each choice be made and that a clear understanding of what the consequences of failure to reach the well completion and/or well control objectives would be.

The subject of cost benefit vs risk as relates to choosing whether to run a liner or a long string will be easier to understand when comparisons between well section conditions and objectives are addressed in paragraph 2.3 of this chapter.

Authors' note

The best approach to use in making an appropriate cost benefit vs risk decision is to always ensure that the choice selected retains a viable and effective way for controlling a well influx without having to force the issue. Luck is not a factor in well engineering. Furthermore, taking a higher risk, when appropriate, should only result in risking higher costs and not well operations integrity which can jeopardize the safety of the operation and personnel.

2.2 Critical elements required to meet well design objectives

The requirements placed on a cement job for casing strings set to achieve different objectives will vary depending on several factors. In the case of conductors that may be either driven or cemented in place, the setting depth requirements are generally based on installing them deep enough to allow the following:

- On land, circulating fluids back to the surface mud tanks while drilling to surface casing setting depth without washing out below the rig, and offshore, to withstand the head of the fluid and cuttings in the annulus back to the seafloor when drilling to reach the depth at which the next casing will be set;
- Having sufficient load carrying capacity so that together with other concentric conductors and surface casing they can support the weight of subsequent strings to be landed at the surface;
- On land, have sufficient shoe integrity to allow diverting operations when drilling surface hole, in the event a shallow flow;

In the case of surface casing, three primary aspects should be considered:

- Total and complete isolation of fresh water sands from contamination from outside sources, except offshore where freshwater is not present below the mudline;
- Strong solid cement at the top with the capability to allow the surface casing and conductor to carry the weight of all subsequent casing strings that will be landed in the wellhead;
- A good sealing shoe with pressure barrier integrity exceeding the fracture gradient of the formations immediately below to allow drilling to the first pressure transition zone, where setting of the next casing string is planned.

Set the casing shoe in shale and if a permeable sand is a short distance below, consider extending the surface hole to leave the sand behind pipe to avoid having a potentially lower integrity formation immediately below the shoe. If a sand formation is within 500 ft of the surface shoe repeat the integrity test to make sure that the maximum fracture gradient is better than the shoe and that the limits on maximum mud weight allowed to drill are valid.

Intermediate casing strings used for drilling into and below a transition zone with a gradual pressure increase through a section and a good margin of mud weight overbalance on the highest pressured formation, with a low risk of lost returns, will normally only require a good shoe. An intermediate liner will require both a good shoe and a good liner top seal. In cases like these there is very little risk of behind pipe formation isolation problems and lower concern about getting cement to do its job.

Intermediate or final production strings (casing or liners) being set in hole sections with the following conditions will present a high risk to annular gas flow during cementing operations and require special considerations to avoid major problems:

- High flow capability hydrocarbon zones;
- Low overbalance pressure margin drilling mud weight on the highest pressure formation;
- High differential pressure between various formations open in the wellbore; or,
- Existence of low stress zones.

When setting either a full string or a liner across the section, the following requirements must be achieved:

- Casing strings: Behind casing zone isolation, a competent shoe, good cement top barrier capability, and special well control considerations post cementing operations;
- Liners: Behind pipe zone isolation, liner top and shoe barrier capability, special well control considerations post cementing operations.

The most important factor that impacts the capability to meet the listed requirements when installing either a full casing string or liner in a well is achieving an effective cement job.

2.2.1 What impairs achieving an effective cement job?

One of the basic issues that must be addressed in order to achieve an effective cement job is the removal of the drilling mud from the casing and hole annulus and replacing it with good clean cement. Failure to do this will result in leaving contaminated cement and/or mud channels in the annulus which can provide pathways for flow from permeable formations that need to be sealed and isolated.

2.2.1.1 Mud displacement efficiency

Many studies and much work have been done over the years to investigate and improve the mechanics of displacing mud with cement from behind casing strings. Two general conclusions that have resulted from work on this subject are that:

- A good drilling fluid is not the idea fluid to be displaced from the hole by cement;
- It is almost impossible to remove all of the mud from behind pipe without moving the pipe before, and during the cement job until the plug bumps.

Rotating the pipe is best. Also, rotation vs reciprocation of the pipe reduces the risk of sticking the pipe in the wrong position, which can complicate the ability to land the hanger and of creating surge and swab wellbore problems.

Good drilling mud is designed to suspend weighting material and to remove drill cuttings from the hole while drilling which results in having a mud with high gel strengths and viscosities at low shear rates. Muds with these properties are highly immobile next to the hole and casing walls. Even when casing is centralized preferential flow will be away from the walls. In most cases if the hole is not in gauge the hole will be elliptical and the pipe will be off center to the low side of the hole. Circulating without pipe movement will cause mud to flow up the high side of the annulus, where the larger cross-sectional area exists. Rotation of the pipe will cause the pipe to change its relative position in the hole and also helps mix and breakup the gels while dragging immobile mud from the low side of the hole to the flowing side. Reciprocation also helps breakup the gels but the position of the pipe relative to the hole will not change causing the mud on the low side of the hole to remain there.

Figure 2-1 presents the results of a study done with hole and casing models in a lab controlled environment to measure the displacement efficiency of mud by cement under various mechanical parameters. (See reference at bottom of Figure 2-1.) To reduce the number of variables to contend with, these tests were done using cement and mud of the same density and with centralized pipe in a gauge hole. The tests were designed to study the differentiating benefits of flow regime (turbulent vs laminar flow), no pipe movement, reciprocation, rotation and with and without the use of cementing aids (rotating or reciprocating scratchers). The tests were done while simulating circulation using the same volume of cement in the models for each test. The displacement efficiencies were determined by crosscutting models at very close intervals (after the cement set) and then planimetering the areas of cement vs mud left behind in the cemented test models. As the data clearly shows, the higher displacement efficiencies occurred with pipe rotation compared to all cases even when the other parameters such as gravity difference between mud and cement and flow properties were not optimized. Additional tests done later after the referenced paper was written, using weighted muds and cement with gravity differences and optimized mud properties done as part of a study on rotating liners, showed additional efficiency improvements into the high 90s using rotation vs other options. Combined rotation and reciprocation showed no further improvement over rotation alone. (See Reference API, Standard 65 Part 2, 2nd. Edition December 2010, 5.6.5.6 Pipe Movement.)

A more detailed discussion of good cementing practices for improved mud displacement by cement is presented in Chapter 8 of this book. In general these include the following:

Mud displacement study-effect of pipe movement and scratchers (cement density equals mud density)

Test #	Flow Regime	Pipe Movement*	Displacement Efficiency, %
3	Laminar	None	60
10	Turbulent	None	66
24	Laminar	ROT-16	84
25	Turbulent	ROT-16	83
26	Laminar	RCP-1.5	77
27	Turbulent	RCP-1.5	79
34	Laminar	ROT-16†	93
35	Turbulent	ROT-16†	92
36	Turbulent	RCP-1.5†	90

* ROT = rotation, rpm: RCP = reciprocation, ft/sec
† Included the use of scratchers

Figure 2-1: Mud displacement mechanics study. The pipe must be moved to displace the mud. Clark, C. R. and Carter, L. G. ,"Mud Displacement with Cement Slurries" Journal of Petroleum Technology (July 1973), Table 2, pp 775-783.

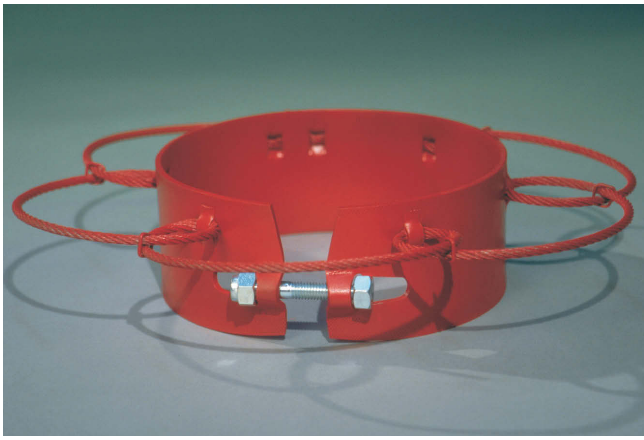
- Treat the mud prior to cementing to reduce the gel strength and low shear rate viscosity as much as possible without dropping weighting material from the mud. Work with the mud company representative to design the best cementing mud properties possible;
- Drill a gauge hole ;
- Centralize the casing (use solid body centralizers on deviated or horizontal holes);
- Rotate the pipe before and during the cement job until the plug bumps;
- Use plenty of spacer to water- wet the casing and formation and to improve displacement of either water base mud or NAF. NAF drilling mud mixed with, or in contact with cement inhibits it from setting, good spacer fluid does not.
- Use spacer with density that is higher than the mud and cement with density greater than the spacer to get gravity assist during displacement but always calculate equivalent circulating density while cementing to ensure that the fracture gradient of the formations in the hole being cemented are not exceeded.

Other important considerations:

- Use cable-type loop scratchers on casing to further enhance mud gel break-up and/or thick filter cake removal when it is a problem (see Figure 2-2);
- Use solid body roller-imbedded non-rotating centralizers on high angle and horizontal holes to allow pipe centralization and rotation at lower torque during cementing operations.

2.2.2 Cement column behavior after placement

The second concern impacting the ability to get a good cement job comes after the cement is in place and after the cement slurry begins to thicken. Thickening or gelation of the



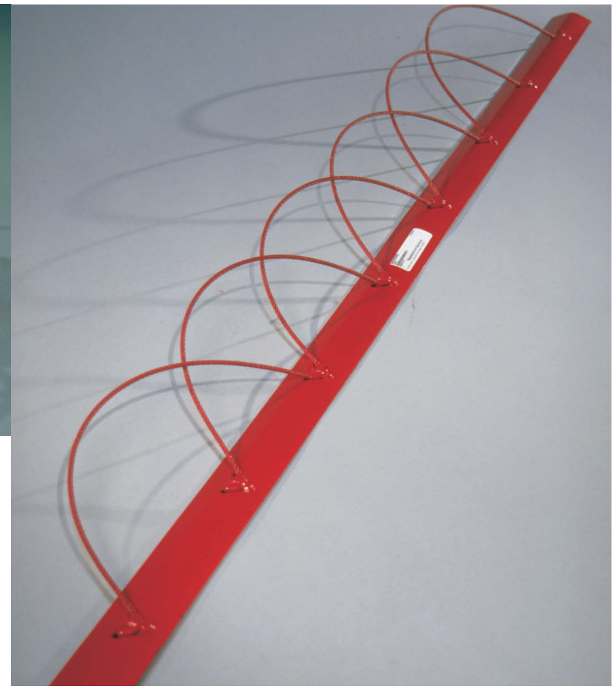


Figure 2-2: Cement displacement aids - reciprocating looped cable scratcher (above) and a rotating looped cable scratcher. Courtesy Weatherford.

cement, fluid loss and the cement interaction with the hole and casing can cause a drop in column pressure and a deterioration in the cement's ability to maintain hydrostatic pressure continuity of the cement column itself, as well as from the mud column above the cement. This usually happens very quickly after the cement is in place and long before the cement has set and attained sufficient compressive strength to contain formation pressures if hydrostatic pressure in the wellbore should drop below the formation pressure. Cement gelation on its own does not initiate a loss of the hydrostatic pressure of the column, because there is continuity immediately after the cement is put in place. When the pumps are shut down and circulation stops, the static in situ pressure of the incompressible column at any given depth of the well at that instant is equal to the hydrostatic pressure of the mud and cement column above. What causes the loss of pressure in the column after pumping stops and the cement begins to thicken, are the self-supporting behavior of the cement solids and the interaction of the cement with the walls of the casing and hole (the column acts like thick grease vs oil). Additionally, loss of fluid from the relatively incompressible cement mass either through shrinkage, due to the cement hydration process, water filtration to permeable formations, or free water migration upward due to gravity also contributes to the pressure loss in the column. As the cement mass continues to thicken the hydrostatic pressure from the mud column above can also no longer freely communicate through the cement column matrix to the formations below. The only way that the mud head above could be reestablished would be, if somehow the differential pressure between the mud above the column of cement and the formation below would result in enough force to break the gel strength of the cement. This is normally not the case because the pressure in the formations below the cement may only be slightly less or close to balance compared to the pressure of the mud column alone above the cement. As fluid loss and the gelation process in the cement continues, pressure in the cement column continues to fall, so that eventually the pressure in the column drops to that of the highest pressure formation in the section. At this stage, fluids from the high pressure formations can invade the cement. If the cement has mud channels, is not fully set, or has insufficient strength to resist flow, the well fluids (oil & gas) can percolate or break through the cement and flow towards the surface. The potential solution to this scenario is a race against time. The keys to mitigating this phenomenon basically involve the ability to achieve some combination of the following:

- A reduction of the loss of fluid from the cement after it is in place;
- The ability to maintain at least some overbalance on the formations by the combined column of mud and cement so that even a small minimum of positive pressure margin can be maintained on the potential flow zones;
- Accelerating the setting time of the cement placed opposite the potential flow zone's face to achieve enough gel and compressive strength to provide sealing capability while the slurry above can still partially maintain column continuity until the zone is isolated. What has the industry done to try to understand and solve this problem?

2.2.2.1 Investigations into the causes for annular gas flow after cementing operations

Figure 2-3 presents the results of one of a series of tests conducted as a part of a study done over a seven year period to investigate the causes and potential solutions for the phenomenon known in the industry as "Annular gas flow following cementing operations". The results of this study which included lab modeling simulations of cementing operations, and field work to observe cement column behavior to verify the lab results in actual wells were reported in an SPE paper entitled "An Investigation of Annular Gas Flow Following Cementing Operation", S.P.E. Annual Symposium, Houston Texas, January 1976. API Standard 65-Part 2 Second Edition, Dec. 2010, entitled "Isolating Potential Flow Zones During Well Construction" cited the importance of this work in clearly identifying the cause for well annular flow following cementing operations.

2.2.2.2 Model studies to investigate cement column pressure behavior

The data presented on Figure 2-3 shows the pressure behavior of a cement column over time after it is placed in a hole under conditions that simulated using a single recipe cement slurry that first begins to thicken and set near the upper part of the column. This is not an uncommon occurrence when a string of casing is cemented in a well where the hottest circulated fluid in the wellbore will be one quarter to one third of the distance off bottom and also where the slurry which was mixed first will wind up in the annulus when the cement is in place. This combination of having the hottest and first-mixed slurry placed at or near the top of the cement column causes that part of the column to begin to thicken ahead of the bottom portion. The test model for simulating this occurrence consisted of a solid body, 20-ft vertical, 2–in. diameter pipe which was instrumented with sensors to collect pressure and temperature data at several points in the column while the test was being conducted. A drawing to the right of the graph shows the location of the temperature and pressure sensors on the model. The pipe was filled with an 18.4 ppg cement slurry made from class-A cement, silica, hematite, 2% salt, retarder, 46% water and no special fluid loss control additives. Heating tape was installed outside the pipe at the halfway point of the column in order to heat the cement and accelerate setting of the column at a point some distance off bottom to simulate a typical occurrence that is common during most cement jobs. This test was run to study the pressure behavior of the cement column while setting without any influence from potential fluid loss to permeable formations in a wellbore. The charts on the graph show the effects of the cement thickening and finally setting. Note that the pressure began to drop almost immediately after the cement was placed in the pipe. These tests show both the effect of the cement thickening (gelation) as the temperature was increasing at the midway point by the heating tape, and from shrinkage due to hydration and also from free water migration up the column due to gravity. The gelation and shrinkage combination causes loss of the original in situ column pressure. The lowest pressure recorded on the bottom gauge was 12.2 psi or a 40% loss from the original in situ pressure of just over 20.2 psi that was induced by the 18.4-ppg cement. The final pressure when the cement was set was equivalent to 11.7 ppg.

Other model testing done to simulate fluid loss through an external permeable sand section installed below the hot spot in the model showed an even greater column pressure loss when compared to the results shown for the solid pipe model used in Figure 2-3. The model tests simulating fluid loss were done with the same cement and schedule except that free water was allowed to bleed out across the permeable filter medium as the cement was setting by controlling

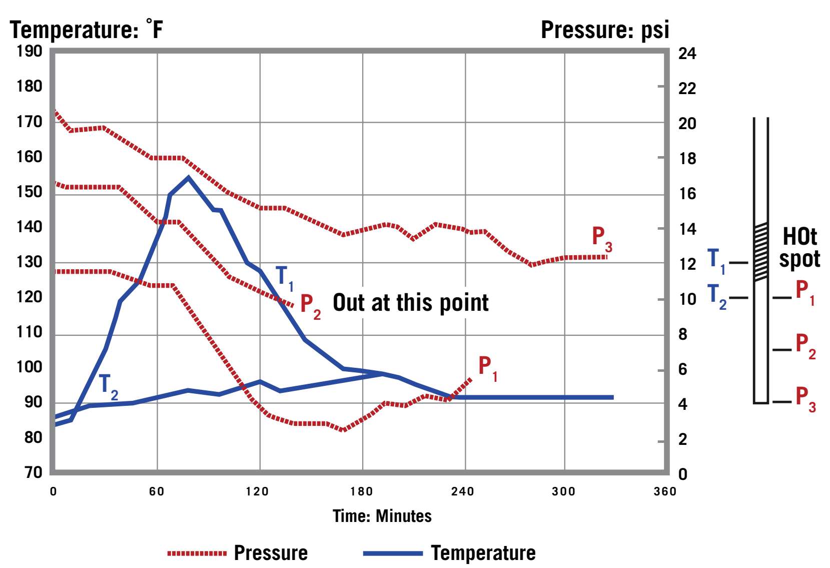


Figure 2-3: Setting cement column behavior - model test results from investigation of column pressure loss vs. time due to cement gelation and free water migration. (Garcia, J.A. & Clark, C.R., "An Investigation of Annular Gas Flow Following Cementing Operations". SPE Annual Symposium, Houston, Texas, January 1976.

the back-pressure behind the medium at a value below the original hydrostatic pressure in the column. The results of this test were no great revelation, but it does help to point out that in wells with high permeability and low formation pressures relative to wellbore hydrostatic pressures, filtration control of mud and cement can play an important function in trying to retain cementing column in situ pressures.

Another test carried out to study the effects of water migration on cement column pressure behavior used a model like the one used on Figure 2-3, that was modified using a thin rubber membrane placed between two flanges half way up the cement column. This model was designed to allow pressure communication through the column but to prevent water from gravity migrating towards the top of the pipe from the lower half of the cement column during the test. Cement was placed in the lower half of the model; the membrane was installed between the flanges, which were then joined, and the top part of the model was filled with the rest of the cement. The heating tape was placed above the flanges and the test was commenced. The pressure in the column at the bottom of the model below the membrane never dropped below the starting value, and actually increased slightly tracking the temperature being recorded during the test. Inspection of the model after the test showed water from the slurry placed in the bottom half of the test pipe had accumulated under the membrane and not allowed to escape causing a concave bulge, or dome, upward towards the top of the model. This shape would indicate a pressure differential towards the top was created when pressure at the base of the column above the membrane dropped as the cement thickened and water from the upper portion was allow to migrate towards the open top of the model (just like it did in the model used in Figure 2-3). The dome shape of the membrane placed between the upper and lower columns of cement, as witnessed after the test, and the pressures recorded during the test clearly showed that not allowing the water to escape from the lower column had helped trap the original in situ column pressure below the hot spot. This test confirmed that that managing water loss from the slurry, regardless of the cause, can help reduce the loss of original head in a cement column.

2.2.2.3 Investigation into how cement composition affects column pressure behavior

Since these tests seem to indicate that water migration and fluid loss after cement column gelation started were the likely causes for the pressure losses in the column, a test was then designed to investigate how changing these fluid properties in the slurry composition would affect the pressure behavior of the cement. The cement used for the new test was modified to have a reduced fluid loss value of 50 cc on a 30-min filtration test and a mix water ratio of 36%. The earlier test reported in Figure 2-3 had no fluid loss control

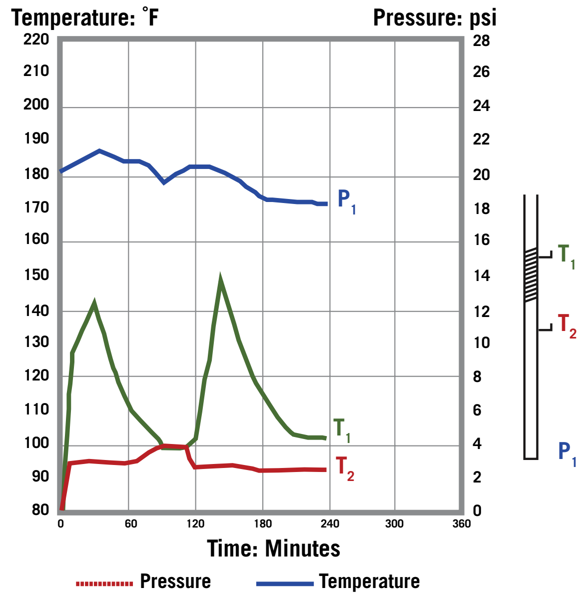


Figure 2-4: Model test results for cement column pressure loss behavior vs. time for low fluid loss cement slurry. (Garcia, J.A. & Clark, C.R., "An Investigation of Annular Gas Flow Following Cementing Operations". SPE Annual Symposium, Houston, Texas, January 1976.

and a mix water ratio of 46%. The fluid loss properties for the slurry were reduced by using polymers and latex. The density for the slurry with the lower mix water ratio was adjusted to the same 18.4 ppg as in the higher mix water ratio cement used in the first test, by reducing the amount of hematite.

Figure 2-4 shows the pressure behavior of cement during the test using the slurry with a lower mix water ratio and a lower fluid loss in a similar model test to the results shown on Figure 2-3 for the higher fluid loss and higher mix water ratio slurry. The model for this test was simplified to only record pressure at the bottom of the column because the prior test confirmed that in cases where pressures were recorded at various points all data was tracking showing agreement at all points. As the graph showing the model test results indicate, the pressure at the bottom of the model when the test began was approximately the same as for the one with the higher mix water ratio cement in Figure 2-3, at just over 20.2 psi. The column pressures in this test seemed to initially go up slightly and appeared to respond to temperature fluctuations although at the end the pressure eventually dropped to 18.2 psi from an initial pressure of 20.2 psi. This is a pressure loss of 10% from the starting pressure vs a 40% drop when the test was conducted with the higher water loss and mix water ratio cement. This is a dramatically different behavior between the two slurries' initial pressures. Since these tests were done in a closed system with no filtration loss of fluid to a permeable section the behavior was purely due to the slurry properties. The conclusions that can be drawn for these results would suggest that, because there is less free water in this slurry, the gel strength of this cement aided by the latex would be stronger making it harder for the lower volume of free water to migrate upward through the cement matrix due to gravity. The net result would be that more of the original in situ pressure would be retained. Although a test using a permeable section in the model to allow simulation of fluid loss from the column was not conducted with this slurry, it would follow that a slurry with lower fluid loss control would also result in reduced pressure loss due a lower net filtration loss.

2.2.2.4 Field testing done to corroborate lab results

The second part of the study described above, done to help corroborate the model findings, involved a study on actual wells in a field where annular pressure following cementing operation often occurred. These field tests involved the use of noise logs to monitor fluid movement in the cement column after placement in a well. (Noise logging is an Exxon Patented technique designed to listen for flow behind pipe using downhole microphones. The technique is capable of measuring flow rates and type of fluid movement behind pipe.) The noise logs were used to define the time when the pressure in the wellbore dropped to a point of allowing flow into the wellbore to occur. These logs also helped identify cases where there was communication between zones below the cement top, regardless of whether pressure was ever noted on the annulus of the well at the surface. The field studies confirmed the observations from the model tests that hydrostatic pressure loss in a cement column occurs before the cement sets, and that when this happens the well will flow once the overbalance pressure is lost. The field test also helped identify related problems associated with cement column pressure losses that can lead to underground communication between zones of different pressures.

Other work done later by Cooke, Kluck & Medrano, Exxon, JPT, August 1983, where they installed pressure gauges on the outside of a casing string to record pressure behavior of a cement column during and after pumping a cement slurry in place on a well, corroborated the findings of the model work and are reported in detail in Chapter 8 of this book.

2.2.2.5 Conclusions and recommendations to address annular gas flow problems

The conclusions from the work reported above have helped to define the causes for the phenomenon known as "Annular Gas Flow Following Cementing Operations" and have also helped find solutions to the problem and hazards they present.

In general the best practices recommended to address the maintenance of column pressure when cementing are as follows:

- Use a cement composition with the lowest fluid loss and lowest mix water ratio possible;
- Tailor the cement job so that the setting times for the cement slurries will set from the bottom up. This will allow the sealing off of the highest pressured formations while the cement above is still fluid and capable of maintaining pressure continuity to the lower section of the hole;
- Maximize displacement efficiency by cement to avoid leaving mud channels and contaminated cement across the interval being cemented. See "mud displacement efficiency" discussed earlier in this chapter (paragraph 2.2.1.1) and in greater detail in Chapter 8 of this book;
- When flow-capable zones are being left behind pipe select the right completion design to avoid losing the hydrostatic head of the mud atop a cement column following placement of the cement. When running a liner, do not run an integral liner top packer in a situation where high flow potential from an open formation exists, and a low integrity zone is also present in the same section of hole. The hydrostatic pressure of the mud above the hanger must be maintained on the cement column after placement in the hole to prevent an influx from flow-capable formation in the section. If a packer is to be used, it should be run later on a separate trip after the cement has set and after cleaning out and testing the liner top. When these wellbore conditions exist it is also not a good application for using an expandable hanger, because expanding the hanger to seal against the outer casing after placing the cement cuts-off the hydrostatic head of the mud above the hanger from the cement below before it has set. On a deep-water well, land the hanger but delay setting a casing hanger pack-off (which if set will cut off the hydrostatic pressure head of the mud above the hanger in the riser) until after the cement has had adequate time to set. Delaying the setting of the pack-off will maintain the full mud head in the riser above on the cement and also allows monitoring of the annulus to ensure that the formations have been sealed and no annular gas flow is occurring behind pipe. Failure to maintain adequate head on top of a cement column until the cement has sufficient gel strength to prevent gas migration can cause an influx from flow-capable formations and/or cross-flow between formations;
- Where applicable, design the cement job to allow for supplementing the hydrostatic head above the cement by applying pressure and/or monitoring the top of the cement column until it sets. The only practical way to add pressure to the cement column after the cement is in place is when a liner is installed and pressure can be applied through the drill pipe, from a short distance above the hanger,

while reversing or circulating fluid and holding back pressure that can be trapped downhole. (For details on how to do this correctly see a discussion in Appendix 2A on the subject of running, setting and cementing liners and tieback strings) Pressuring up on a static column of mud from the surface is not an effective way of getting pressure down the hole and also carries the risk of breaking the well down in the weaker upper sections of the hole.

2.2.2.6 Quantifying and mitigating pressure loss in a cement column in field applications

(Reference API Standard 65, Part-2, 2nd Edition, December 2010) This API Standard, "Isolating Potential Flow Zones During Well Construction", is the product of a committee of industry experts brought together in late 2010 to update guidelines to "help prevent and/or control flows just prior to, during and after primary cementing operations". Section 5.7.8, Static Gel Strength, describes how studies, experimental data and field results have been used to develop an empirical method for estimating when the static gel strength (SGS) of a cement slurry placed in a wellbore reaches a critical point, when the cement column pressure decays enough to cause an underbalance of the highest pressure formation in the well. This point is referred to as the Critical Static Gel Strength (CSGS). If the combined hydrostatic pressure of the decayed cement column and the mud column above the cement reaches a point of matching the pressure of a potential flow formation in the well, it can cause the formation to invade the wellbore and potentially initiate flow.

The majority of the drop in the hydrostatic pressure in a column is caused by the self-supporting characteristics of the cement slurry and the interaction of the gelled fluid with the walls of the hole and the casing. Chemical shrinkage and fluid loss will also contribute to the loss in hydrostatic pressure, but to a lesser extent, except in the case where very permeable low pressured formations may be exposed in the section. Chemical shrinkage is inherent to Portland cement and cannot be eliminated in a cement slurry. Fluid loss to formations can be controlled through the use of additives in the cement and a fluid loss value of less than 50 cc/30 min is generally recommended for gas migration control.

The point at which the gel strength of the cement has thickened enough to decay the hydrostatic pressure of the column so that it is equal to the pressure of a given potential flow zone, the Critical Static Gel Strength (CSGS), can be determined by using the following equation:

$$CSGS = (300) \times (OBP) / (L / (D_{OH} - D_{CSG}))$$

Where:

CSGS = Critical Static Gel Strength (lbf/100 sq ft)
300 = Conversion factor
OBP = Overbalance pressure (psi)= Initial hydrostatic pressure of the mud and cement column at the flow zone (psi) – Pore pressure (psi) of the flow zone
L = Cement column height above flow zone (ft)
D_{OH} = Diameter of open hole (in.)
D_{CSG} = Diameter of casing (in.)

Experimental data has indicated that a cement slurry static gel strength value that exceeds 500 lbf/100 sq ft will prevent gas from percolating through it. If the CSGS value for a well cementing case being considered is significantly below 500 lbf/100 sq ft the chance for flow from the formation is high. For example, if the CSGS for the case is 200 lbf/100 sq ft, pressure deterioration of the column to a point of balancing the formation pressure will occur when the gel strength is too low to prevent gas from entering the wellbore or from percolating up through the cement column.

One of the ways to increase the CSGS would be to increase the initial overbalance of the column by increasing the mud and/or cement density, but fracture gradient limits of the hole can limit the ability to do so. (On a long casing string that will be set a long distance below a weak casing shoe above, it may be possible to use a heavy mud pill ahead of the cement to provided added hydrostatic head on the cement column below without impacting the fracture limit of the upper shoe). A shorter cement column above the potential flow zone and a bigger hole size or smaller casing would also help, but making significant geometry changes to the well configuration will also typically be fairly restricted.

After making whatever adjustments are possible to establish the highest CSGS value achievable for the wellbore cementing case in question the slurry to be used should be tested in the lab, at downhole temperature, to determine its Critical Gel Strength period, CGSP. The CGSP for the slurry is a measurement of how much time it will take for the cement to go from its CSGS value (when the potential gas flow zone becomes underbalanced) to the desired gel strength of 500 lbf/100 sq ft, which is needed to prevent gas percolation from occurring if gas enters the wellbore. This time period should be as short as possible in order to help prevent flow from occurring in severe flow potential wells. (If the slurry can reach the gel strength of 500 lbf/100 sq ft value fairly quickly after gas enters it may prevent the gas from migrating very far before it can be trapped).

With this information one possible solution to the problem would be to change the design of the slurry so that it will take a very short time to attain a Static Gel Strength value of 500 lbf/100 sq ft after its CSGS is reached when the potential for flow from a formation that is no longer overbalanced can occur. According to the referenced standard a Critical Gel Strength Period of less than 45 minutes has proven effective in preventing flow from occurring when flow potential is determined to be severe. Slurry design can also be altered in ways that make it more difficult for gas to percolate through it by the use of additives such as latex to decrease the permeability of the cement matrix.

Alternatively another possible solution is to design a two slurry system (lead and tail) to address the problem. The tail slurry that is positioned opposite the potential flow zone, and a very short distance above, should have a very quick build-up to the 500 lbf/100 sq ft gel strength and beyond required to prevent percolation and, if possible, soon after at least 50 psi compressive strength. The lead slurry, above the tail and above the flow zones should have a low and delayed gel strength build-up, so that the CSGS value at the potential flow zones below is not reached until the tail slurry has done its job of sealing off the potential problem. With this approach the objective is to have the lead slurry behave more like mud that can transmit hydrostatic pressure during the period when the tail slurry is setting. This is not totally possible because although the lead slurry will have a low and delayed gel strength build-up, it will still have some gelation occurring once it has been placed in the hole and becomes static. A computer analysis can be used to determine the pressure decay vs time at the base of the lead slurry, and the resulting pressure for the combined two slurry column at the zones of interest, to ensure that the overbalance condition can be maintained until they have been effectively isolated. The column height required for the tail slurry can also be determined from this analysis. (See Chapter 8 on Cementing for an example case using a manual procedure that demonstrates how the concept of column pressure management, and cement slurry setting time control can be used to avoid annular gas flow in high risk wells.)

This is a complex problem that requires close cooperation between the operator and the cementing company in order to develop the right cement and a plan to achieve a successful job execution.

2.3 Selecting the right well design to meet the section and well objective

As outlined at the beginning of this chapter, selecting how an interval of hole should be cased and the procedures required to meet the desired objectives for the section and the well plan ahead, should be driven by several important considerations. These decisions should be based on formation isolation and cement quality requirements, well control considerations, and a realistic assessment of risks associated with each choice made, including the consequences of failure to achieve the well and/or well control objectives.

2.3.1 Surface casing

In some instances the decision is simple, as for example, in the case of surface casing. Surface casing is usually cemented inside one or more conductors, depending on soil and load analysis, and cemented to the surface. (General guidelines on conductor requirements were discussed earlier in paragraph 2.2.) On land wells sometimes load mats welded to the casing can help distribute very heavy casing loads when soil conditions warrant additional support. The cement job requirements include having good solid cement at the top to help distribute subsequent surface landed casing load to the conductors, good cement in the annulus to completely isolate and protect fresh water sources from communication with other potential brackish water in the interval and solid uncontaminated cement at the shoe. Generally a good cement job can be achieved by centralizing the casing, conditioning the mud which is normally water and gel, moving the pipe while cementing, pumping a good spacer and plenty of excess cement to sweep the hole resulting in uncontaminated cement at the top. Sometimes a top job with neat cement can be done using small pipe between the surface casing and the conductor to further ensure strong cement at the top for load carrying capacity and also to keep the top full if the level should drop after cementing. Using a tail slurry of neat cement around the shoe can also help ensure having a solid shoe cement job.

Casing setting depth for surface casing is determined by regulations for protection of fresh water (where fresh water is present in the surface hole) from possible contamination from chemicals used in the mud to drill deeper and also from other potential salt water zones that may exist in the surface hole. The depth is also selected to ensure that the formations below the shoe will have sufficient fracture gradient strength to allow drilling to the next planned casing point.

In cases where isolated shallow gas pockets may be present in the surface hole consideration should be given to setting and cementing a conductor deep enough to allow installing a diverter or rotating head and blooey line which will permit shutting off a gas entry from reaching the floor and allow diverting of the gas away from the rig. Other measures should be in place to have sufficient mud to attempt a dynamic kill if necessary. If there is a potential for flow from a known or suspected more extensive gas source in the area this should lead to a design of the well to set casing or casings at a depth where the formations have sufficiently high integrity to drill with the mud weight required to prevent an influx and to safely shut-in and kill the well if necessary.

2.3.2 First pressure string (below surface casing)

The first string of casing set below the surface casing is typically a protective string into the first pressure transition zone at a depth where the required mud weight to drill deeper approaches the allowable mud weight margin for the fracture gradient capacity at the surface casing shoe or other lower integrity formation in the hole section above. In a conventional design land well this is normally a long string landed at the wellhead to cover the surface casing, to allow drilling into higher pressured formations. This is necessary because the surface casing typically does not have the burst capacity to withstand the higher mud weights required to drill ahead, or to withstand the possible shut-in pressures from a kick.

In other special cases such as the one presented in Chapter 1 for an unconventional design (Figure 1-6), an early liner hung and set below a higher pressure capacity surface casing than typically used, can result in an overall better choice from a well design perspective. Setting a liner as an extension to the surface casing results in attaining a higher fracture gradient at a deeper shoe which allows drilling deeper into the transition zone than the fracture gradient at the surface casing shoe would allow. This design can result in ultimately setting a smaller diameter protective casing string deeper than in the conventional case and provides a higher pressure capability protective string for drilling the highest pressure section of the well below. The full protective string would be run and landed at the wellhead and designed to protect the surface casing and short liner below it from the mud weight and pressures needed to drill below the transition zone and on to TD.

2.3.2.1 Exception for offshore deepwater wells

In an offshore well in deepwater (greater than 1,000 ft), where the mud column in the drilling riser imposes a high hydrostatic pressure on shallow formations starting at the mud line, it will require setting multiple short liners in succession; to reach the deeper, higher stress formations with sufficient fracture capacity to set a full protective string that will allow drilling into deeper pressure transition zones. The reason that several short liners are required at shallow depths is because the weight of the rocks (overburden) which directly impacts the stress and fracture capacity of the buried formations only begins at the mudline; while the internal wellbore pressure from the drilling fluid mud column exists all the way from the rig at some distance above sea level. On a subsea deep-water well in 5,000 ft of water the internal hydrostatic pressure at the wellhead (mudline) is equal to the head of the mud in the riser. The fracture gradient capacity of the formations below the mudline will only be slightly higher than the pore pressure (usually no more than 1-1 ½ ppg higher) to depths down to 8,000-10,000 ft below the mudline. This is because the overburden weight of rocks from the mudline to sea level is missing and is only replaced by seawater between the mudline and the rig which is about 2.3 times lighter than rock. As drilling progresses in the shallow part of the well, pore pressure increases and the mud weight has to be raised. When this happens even slight increases in mudweight quickly approach the fracture gradient of the lower integrity formations at the shoe above and the section has to be cased off and isolated with a short liner. This process is repeated until the overburden weight of the rocks becomes significant and the resulting fracture gradient increases enough to provide some relative separation between pore pressure and the fracture integrity of the rocks. (Ref. Christman S.A. Offshore Frac Gradients and Casing Setting Depths, 1972 annual Fall Mtg. SPE 4133.)

On a land well the hydrostatic pressure from the mud column in the wellbore is almost negligible inside the wellhead at ground level where the well begins. (The actual mud head at ground level is only impacted by the distance from the wellhead to the top of the bell nipple.) When the well reaches 1,000 ft the pressure inside the wellbore is equal to the hydrostatic head of the drilling mud (Example: (9.5 ppg X 0.052 X 1,000 ft = 494 psi) The fracture gradient of the formations at 1,000 ft will be about 600-700 psi, due to the formation's overburden above. At very deep depths on a land well the fracture gradients driven by highly compacted overburden will ultimately approach 1 psi/ft.

2.3.2.2 Conditions that determine how the protective interval should be cemented

Generally when the first casing string below surface casing is set the section being cased will not have a high flow capable hydrocarbon zone in the transition interval and the pressure will gradually increase over the section. If drilling into a transition zone is below an old shallower field where field pays exist, they likely will have a high margin of excess overbalance from the mud weight being used to drill into the higher pressured below. Under these conditions the possibility for annular gas flow after cementing the protective string, where the cement will have to cover the field pays, will be low if the cement job is done correctly. (An analysis using CSGS equation and cement testing to determine the CGSP should be done to design the job so that any potential flow zones can be cemented effectively without high risk of annular flow following the cementing procedure). The requirements for isolating the section will include getting a good shoe for drilling ahead and a good cement job across the lower pressured producing zones between the surface casing shoe and the bottom of the section (Figure 2-5). The cement top should be brought to a depth that will provide casing stability in the unsupported free pipe section when high circulating temperatures and high mud weights for drilling deeper could lead to casing buckling and wear. (See Chapter 10, Load and Stability Analysis of Casing Strings, for determining how to address the casing stability issue and to calculate axial loads for worst case scenario that are needed to design casing for tension and compression).

When cementing the long string for this case the best cementing practices discussed in section 2.2.1.1 above and in Chapter 8 should be followed. After finishing the cement job

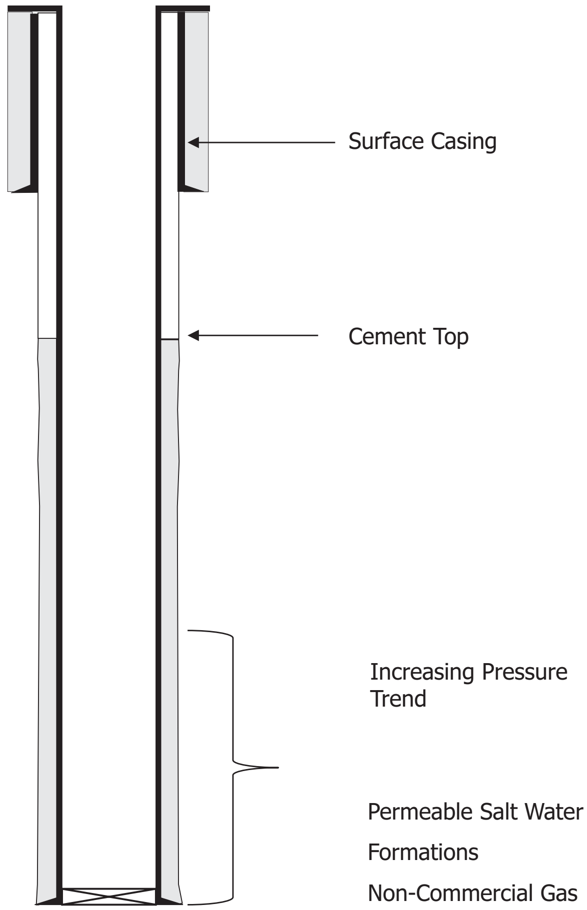


Figure 2-5: First pressure string below surface casing (low risk case) Set long string, cement the well using best practices to isolate pressure interval and obtain good shoe integrity.

and landing the casing the annulus should be monitored for pressure and/or gas build-up and mud should be lubricated via the casing valve if necessary. There should be a very low probability for annular gas flow after cementing a protective casing string under the conditions described above if the cement job design and execution was carried out as outlined.

If a liner is set through the interval as in the case for the unconventional design, or in the case of a subsea well, good cementing practices outlined earlier in this chapter should be applied. If there is little or no risk for flow after cementing this is a good application for using an expandable hanger or a conventional rotating hanger with an optional integral liner top packer (Figure 2-6). Either the expandable hanger or the rotating liner hanger can be rotated before and during the cement job for optimum mud displacement by the cement.

2.3.3 Intermediate string below protective casing (tight hydrocarbon zones and no lost returns zones)

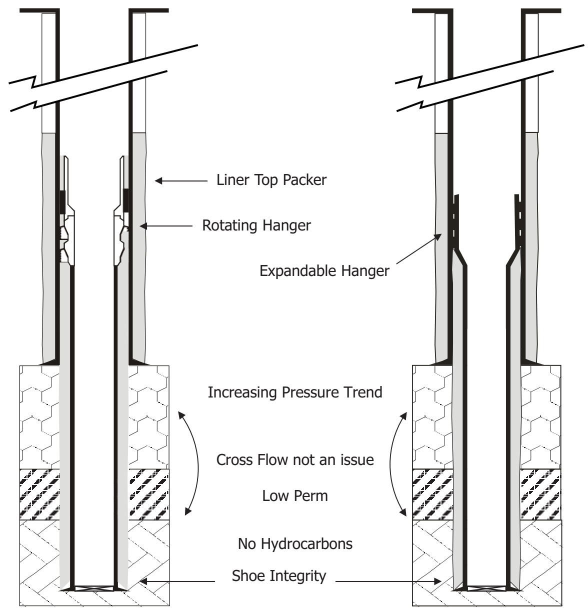


Figure 2-6: Low risk case for annular gas flow from interval below existing casing. Expandable hanger or Rotating liner hanger with/or without integral packer. Use best cementing practices to obtain good shoe and liner top integrity.

Drilling below the protective string into higher pressure requires a steady increase in mud weight to overbalance the formations until the mud weight reaches the allowable safety fracture gradient margin at the last casing shoe above. If this section in the well is tight without the presents of hydrocarbons and does not have a potential for high wellbore seepage or lost returns to low stress formations the section should be cased in the same manner as shown on Figure 2-6. The objectives for isolating the section are as follows:

- A good shoe and a good liner top seal;
- Good cement displacement to secure the section.

If the casing above this section of hole was a long string designed for drilling into higher pressured formation beyond this depth the optimum choice both operationally and costwise is to run a liner. The cement job should be done as follows:

- Use the best cementing practices as outlined in this chapter and Chapter 8;
- Use either a conventional rotating liner hanger with/or without an integral liner top packer or an expandable hanger. Either can and should be rotated before and during the cement job to achieve best displacement results.

See Appendix 2A for detailed procedures for running and setting a rotating liner hanger with or without an integral liner top packer or for running an expandable hanger.

2.3.4 Intermediate string (Problem section: hydrocarbons with low OBP in a section with a low fracture gradient)

Sometimes the highest mud weight that can be used to drill a section below a protective casing or protective liner is only slightly higher than the mud weight required to contain one or more good permeability high pressure formations in the interval. (Refer to Figure 2-7) This is usually the case when there is a limiting fracture gradient in the section being caused by one or more low stress formations. When this combination of factors occurs in the same section of hole the probability for flow before, during or following the cement job will be high. First, lost returns could occur while circulating mud and/or while cementing. Later, loss of the overbalance hydrostatic pressure due to cement gelation and fluid loss may quickly cause an influx situation to occur, before the cement has gained the necessary strength to prevent flow into the well. This scenario of problems in the hole section will require using the best cementing practices possible. This will also require doing a CSGS analysis, and the lab testing necessary to determine and adjust the CGSP, in order to design the cementing procedure and slurries, to manage and reduce the risk of annular gas flow following the cementing procedure. The combination of wellbore conditions in this case requires equipment and procedures that will provide the best capability to accomplish the following:

- A good cement barrier at the top of the liner and the shoe;
- Good cement isolation of the formations behind pipe;
- Good hole monitoring and well control capability until the cement has done its job;
- Provide an added barrier at the liner top after testing cement top both ways.

The best way to accomplish these objectives is to use a conventional rotating liner hanger with a tieback receptacle, but without an integral liner top packer (open annulus). The rotating liner hanger should be run and cemented using the best cementing practices, as previously outlined in this section and in Chapter 8. If the liner for this intermediate section will be the last casing set before drilling the production interval below and if the anticipated hole conditions for the production hole also pose a high probability for annular gas flow after cementing, consideration should be given to designing the liner for the current section to be used in both protective and production service. Installing a combination service intermediate liner through the section above the pays at this point will allow for it to be tied back to the surface later to complete the full production casing string, after the final pay section below is cased, also using a liner. This design approach will save both pipe and related costs

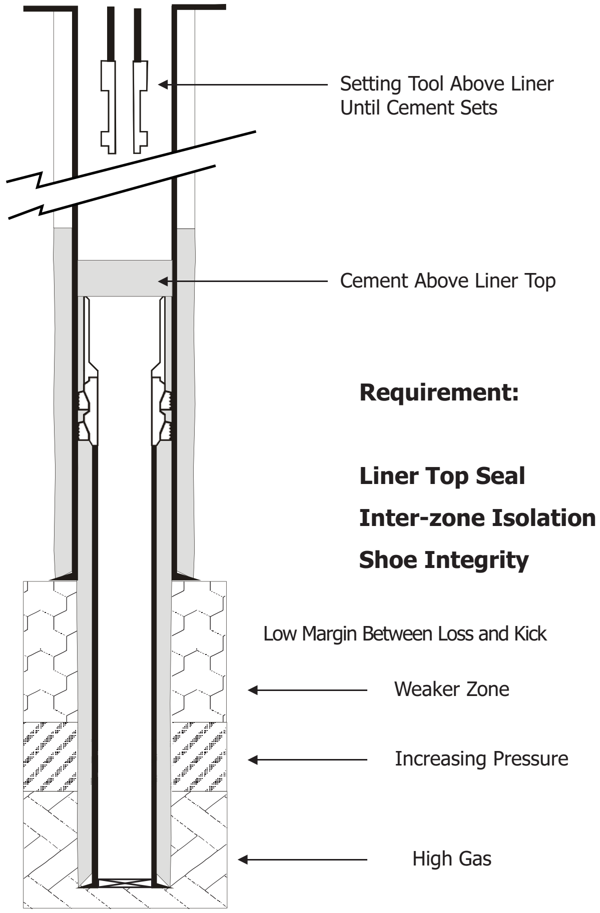


Figure 2-7: High risk case for annular gas flow from section below existing casing. (Hydrocarbons/high perm/ low stress zones/ lost returns formations) Rotating liner hanger with open top (No integral packer). Use best cementing practices & maintain setting tools in the hole to serve as monitoring and kill string if needed.

during completion. (Also see Appendix 2A for details on running and cementing liners and tieback strings as well as the procedures recommended for monitoring and controlling post cementing well conditions.)

The selection and use of a conventional rotating liner hanger without an integral liner top packer (open annulus) but with a tieback receptacle, for the condition outlined above, provides the best capability for achieving the following:

- Rotation of the casing prior to and throughout the cementing operations for the most efficient displacement of mud by cement;
- Safest procedure for retrieving the setting tool to a point above the liner after placing cement in the hole. (Hanger is set and the tool is released and confirmed before cement is pumped in the well. Rotation of the liner is accomplished with the use of a spline located at the top of the hanger. The setting tools are retrieved by simply picking up on the running string after the cement job is completed);

- Only effective way to apply supplemental pressure to the top of the liner and the cement column, if required, to assist in preventing annular gas flow and to monitor the cement job while waiting on cement. Applying pressure to the top of the liner can be accomplished by circulating through the setting string on top of the liner and holding back pressure on the annulus side at the surface;
- Provides a monitoring and kill string to the top of the cement while waiting on cement;
- Provides a test string at the top of the cement to test the job after the cement has set and before pulling out of the hole. Allows both positive and negative test without having to put water on the annulus between the liner running string and the casing;

After the cement job has been tested the user has the option of setting a second independent barrier in the tieback receptacle at the top of the liner hanger by running a liner top packer. If a packer is to be set, it should include a tieback receptacle above it which can be used for running a tieback casing string in the future if planned for completion, or in case it is needed as a result of an upper casing leak while drilling below.

2.3.5 Production interval with good OBP in section with a high fracture gradient

If the production zones are well overbalanced with a good margin of mud weight and the fracture gradient of the lowest integrity zones in the section are significantly higher than the hydrostatic head of the mud in the hole, this section can likely be cemented effectively by running and cementing a long casing string. (Refer to Figure 2-8) The objectives for this section will be to have good isolation of the formations behind pipe, a good barrier above the pay zones, to prevent annular gas flow following the cementing operation, and to be able to monitor and control any potential pressure that might occur after cement placement. The following good cementing practices and operational procedures will be required to ensure attaining the objectives:

- Use best cementing practices as outlined in this chapter and Chapter 8 on cementing in this book;
- Rotate the pipe if possible (Except on subsea wells);
- Centralize the casing above, across, and below the pays;
- Pump at turbulent rates within allowable pressure limits;
- Perform CSGS calculations and CGSP cement testing to ensure that sufficient hydrostatic pressure can be maintained on the potential flow zones until the cement has the strength to prevent gas from entering the wellbore. Adjust mud weight and slurry properties and/or use a two slurry design to meet the requirements;

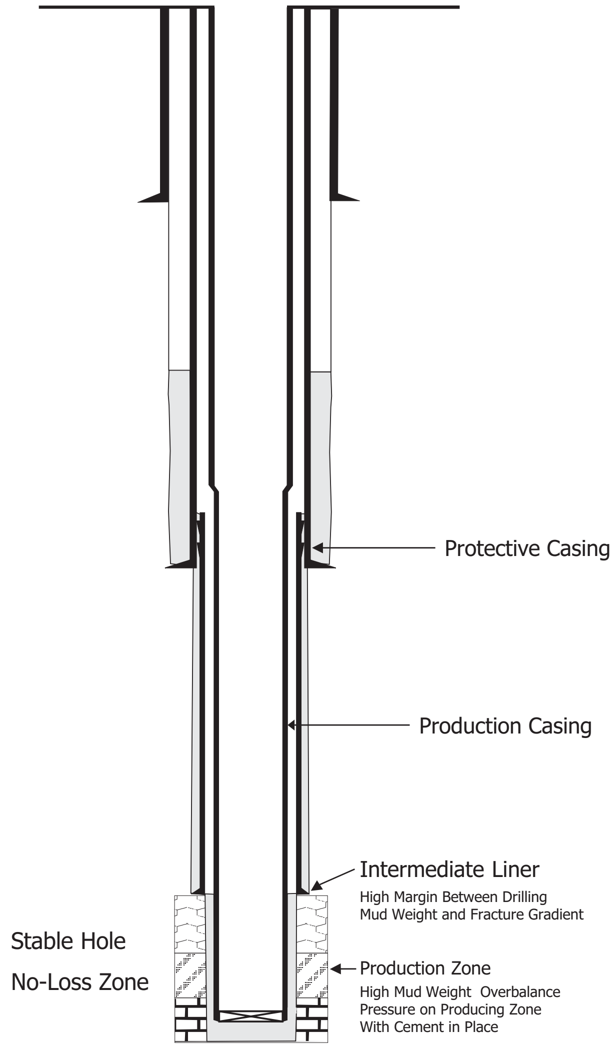


Figure 2-8: Production interval with high margin of overbalance pressure on wellbore from mud and cement. No under stressed formations or lost returns zones in wellbore. Application for longstring using best cementing practices and CSGS/CGSP design for cement job.

- If the well is a sub-sea completion ensure that hydrostatic head of mud above the wellhead can be maintained on the annulus after cementing and that the annulus can be monitored until the cement has done its job. (Delay setting the wellhead pack-off until the cement has set);
- If the well has a surface accessible wellhead, monitor annulus for possible flow until the cement is set.

Note that the cement top for completing the longstring on Figure 2-8 shows the top to be just at the casing shoe of the intermediate liner above. In a real world situation there is no practical way to know exactly where a cement top will wind up after pumping the slurry in a well. In cases where the well cementing requirements results in a cement top being close to the last casing shoe, the safest assumption should be that

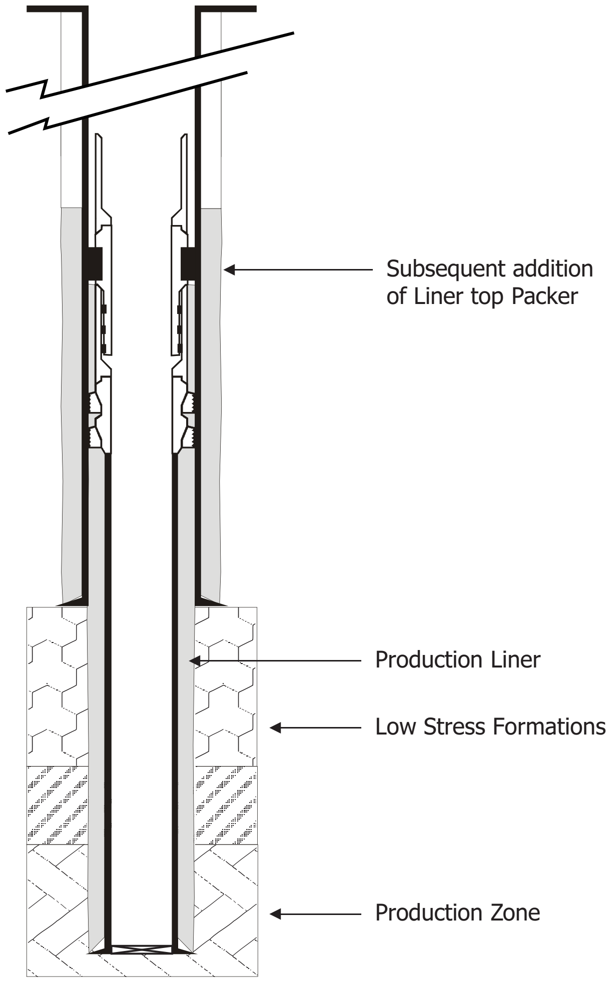


Figure 2-9: Production interval (High pressure producing zone with low margin of overbalance due to low stress formations and/or lost returns potential in the section). Rotating liner hanger application w/o integral packer. Use best cementing practices & keep setting string in the hole to monitor cement job and as kill string if needed. Install liner top packer after testing liner to serve as secondary barrier.

the cement will wind up inside the upper casing leaving a trapped annulus between strings. When this situation occurs it can lead to a casing failure later from heat expansion of the trapped fluids when the well is put on production. To avoid this potential problem it will be necessary to provide a method to monitor and relieve this pressure in the future via surface controls or through the design of a relief system downhole (burst plate) in the outer casing string.

2.3.6 Production interval (Problem section: low OBP on production zone and close margin on fracture gradient)

If the mud weight overbalance pressure on the wellbore formations is low because of section fracture gradient limits and/or because the hole has low integrity formations and a high potential for lost returns this will be a difficult section to cement without experiencing annular flow after cementing. This combination of factors also makes for a good candidate for a well control problem during and after the cement job. The objectives for cementing the section successfully are as follows:

- A good effective cement barrier above the hydrocarbon zone;
- High quality cement isolation of behind pipe zones;
- Ability to monitor and maintain well control capability until the cement has isolated any potential flow formation.

If the casing above the section used for drilling through the pays was designed so that it can be used as part of the production casing, then this section of the hole should be cased and isolated in the same manner as the previously discussed intermediate section with similar challenges and potential problems. (Refer to Figure 2-7.) The best approach is to run and cement a liner with a conventional rotating hanger without an integral liner top packer, but with a tieback receptacle above the hanger. Using this approach will allow the top of the liner to be open to the mud hydrostatic pressure above after the cement is in place and for monitoring and maintaining pressure control of the well via the setting string (serving as a kill string) until the cement has done its job and has been tested. The tieback receptacle on top of the hanger will allow for a liner top packer to be set on a separate trip after the cement job has been conducted and the top of the liner has been cleaned out and tested. Because the liner will be used as the lower portion of the production casing string, the liner top packer will serve as a secondary independent pressure barrier above the pay zones (Figure 2-9). The packer should be designed to include a tieback receptacle which can have future utility in the event that the production casing above is damaged or develops a leak in the future. This choice is valid for either a land or subsea well case.

2.3.7 Special considerations for completing a horizontal production interval in a well

Many of the horizontal wells that are being drilled today (particularly for wells where the production interval is being drilled into a tight zone that is to be perforated and then multi-fracked) involve a design that sets a protective/production combination casing string into the pay zone before drilling the horizontal section. (Figure 2-10). The bottom of the hole where the combination casing is to be set is drilled into the pay zone so that the angle at the casing shoe will be at or near horizontal. After the combination service string is cemented in place the horizontal section is then drilled out from under the casing to the desired reach length. A production liner with a rotating liner hanger can then be run in the horizontal section and hung inside the base of the production/protective casing string and cemented back to the hanger. When a horizontal production interval is drilled,

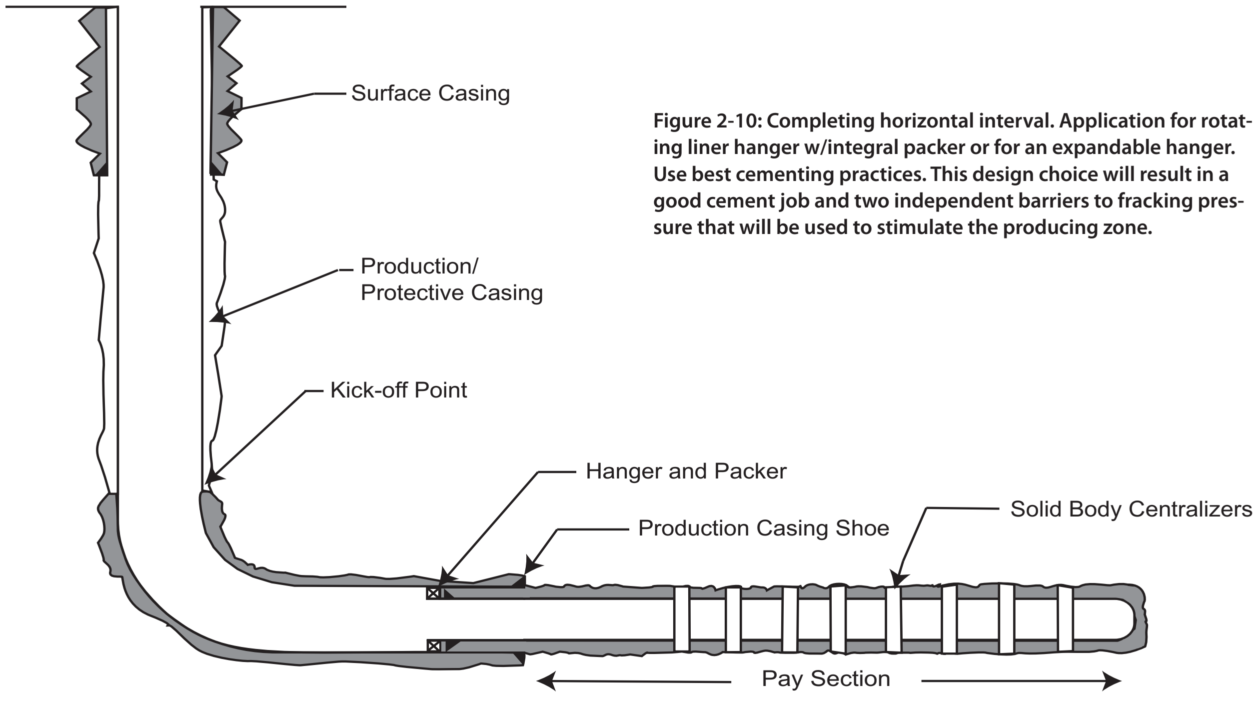


Figure 2-10: Completing horizontal interval. Application for rotating liner hanger w/integral packer or for an expandable hanger. Use best cementing practices. This design choice will result in a good cement job and two independent barriers to fracking pressure that will be used to stimulate the producing zone.

generally the intent is for the hole to be constructed within the same formation, which has a common pressure and fracture strength capacity. Under these conditions the completion procedures to achieve the best and least cost and risk alternative is to cement a rotating liner hanger with an integral liner top packer or to set an expandable hanger that can also allow for the liner to be rotated. (Use these type hangers in conjunction with the best cementing practices as discussed before and use non rotating solid body roller-imbedded centralizers on the casing to manage torque when rotating the liner). Why is using a rotating liner hanger with an integral packer or an expandable hanger the best option for cementing this type well? Because the entire horizontal section has the same pressure and fracture gradient there is no risk of cross-flow occurring once communication with the hydrostatic head from the vertical part of the hole is lost when the top of the liner is sealed by the packer or when the expandable hanger is set. If flow-capable formations should exist and inflow occurs below the packer, this would only re-pressurize the cement in the hole to equal the formation pressure. Nothing else happens because the formation that caused inflow cannot fracture itself. Gravity also cannot cause the inflow to go very far because the hole is horizontal and there is no path to the top of the well because the horizontal section is sealed at the liner top packer. The other advantage of using the hanger with the integral packer or the expandable hanger is that running a hanger without a packer would require an extra trip to set a liner top packer and this can be a risky operation in a horizontal well where the packer can be set accidentally on the way in the hole.

2.3.8 Completion design requiring a tieback string

If a liner cemented across the production interval for any case presented above is being hung below casing that is not designed for production operations, it will be necessary to run a production tieback string from the top of the production liner to the surface to have full production design capability. In the case where an intermediate liner above was designed with the capacity to be used as part of the production casing, the tieback will only have to be run from above the top of the intermediate, production rated liner to the surface, to complete the production string. Because the tieback casing string will be cemented in place for a distance above the liner top tieback receptacle (after the liner top has been tested both ways) the cement job done to secure the tieback will serve as an added independent cement barrier. There is no way to negatively test this second cement barrier provided by the liner tieback, however doing a cement job between casing strings atop a previously tested liner top is very good insurance for having a good seal above the production zone.

In the case of a land well, jackup or platform well where the tieback will be landed on a surface wellhead hanger, the length of the receptacle run atop the production liner hanger should be about 10 ft long, and the seal stinger at the end of the casing tieback should be designed to be a few inches shorter than the receptacle (Ref. Figure 2-11). The casing hanger and tieback landing plan design should allow for the upper locator shoulder at the top of the seals to be a few inches short of tagging on the top of the receptacle, and for the stinger to be a few inches short of tagging

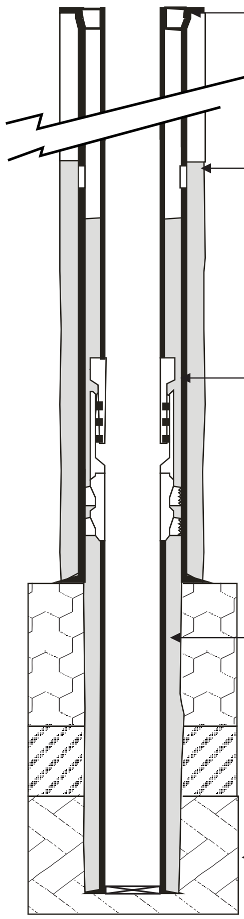


Figure 2-11: Liner tieback application. Liner tieback required on wells where existing casing above production liner is not rated for expected pressure service in a well.

the bottom of the receptacle, when the casing hanger is landed at the surface. The stinger and the receptacle will act like a slip joint to facilitate landing the string. This design will allow for the casing to be landed with full buoyed weight without having the bottom of the string in compression. (See Appendix 2A for detailed procedures to run, cement, space-out and land a tieback correctly as well as other design features required for use of this equipment).

As noted on Figure 2-11, after completing the tieback casing cementing operation most wells likely wind up with a closed annulus above the top of cement (no open shoe in the cemented annulus between strings). To avoid a build-up of pressure between strings, which can lead to casing failures as a result of heat expansion of trapped fluids from production operations, it will be necessary to design a way to relieve pressure build-up over the life of the well. This may involve the use of a surface monitoring and pressure relief system, a burst plate, a weak joint designed into the outer casing string or the use of a compressible fluid system in the annulus.

If the tieback completion is for a subsea well it will be necessary to make yet further special provisions in the design of the equipment and procedures for cementing and landing the string. In order to contend with heave effects and other complexities while cementing and landing a tieback string, it is highly recommended that the tieback receptacle be at least 30 ft long and that the stinger be a minimum of 4 ft shorter than the receptacle. The lower entry guide section of the stinger below the lowest set of seals should also be at least 5 ft long and the cementing ports should be just below the lowest set of seals. (This design will result in allowing the lower end of the stinger to move freely inside the receptacle if heave occurs during the cementing operation and will prevent the potential for the lowest set of seals on the stinger from inadvertently entering the receptacle while circulating or pumping the cement job, and shutting off the cementing ports). These longer ranges for the system will also ensure that sufficient effective seal section can be achieved through the receptacle by allowing for greater tolerances for landing the hanger, while contending with potential heave effects. The longer design range will also facilitate spacing for positioning the hanger to allow landing it without shouldering the locator sub on top of the receptacle, while still leaving a long section of seals inside the receptacle. The proper spacing between seals and the casing hanger for landing the system will have to be done at the surface, when the assembly is first picked up to run in the hole for the cement job. The cement job will still be done in essentially the same manner as for the land and surface wellhead case. (See Appendix 2A for detailed procedures for running, spacing, cementing and landing tieback strings for sub-sea wells.) The pressure tests and procedures to confirm the location of the stinger and receptacle and the hanger can still be done in a similar way to the land case when the equipment is run to bottom. The pressure tests and spacing procedures for the stinger and receptacle also serve to ensure that the seals can be installed without concerns for a hydraulic lock or other obstruction that can prevent the proper placement on the seals in the receptacle. A miscalculation on the length of the string between the casing hanger and the seal locator relative to the wellhead profile and the top of the receptacle will mean having to pull out of the hole, to at least the casing hanger in order to make a correction before conducting the cement job.

Closure

This chapter is intended to teach the well engineer how to establish the requirements and the methods for securing each hole section in a drillwell as driven by hole conditions, risks and section and overall well objectives. The approach is to walk the engineer through the process of determining what service each cased-off section, and the casing itself, should perform in the design and completion of the well.

As mentioned in the introduction to this book and the well design section, the selection of the best proposed method for how each hole section should be completed, and the operational procedures recommended to accomplish the objectives, are not based on personal preferences, but on well-founded technical analysis of the factors that impact the capability to achieve the objectives while appropriately assessing and managing risk. The recommendations are based on extensive lab and field studies presented here as well as from experience tempered by field results over time.

In this section we have also tried to present the topic of risk, not with a matrix using probability, but rather by a serious look at the consequences of failure and what alternative choices in design and operating procedures can do to mitigate unacceptable consequences. This process involves an honest analysis of how a well could behave under a given set of hole conditions and then looking at viable methods to mitigate any potential serious well control situation. When alternatives on how a well should be completed present different risks and a higher risk alternative is selected, that higher risk should only involve higher cost if a problem occurs and never present a higher risk to safety and/or the environment.

APPENDIX 2A: Procedures for running and setting liner hangers and for cementing liners and tieback strings

2A.1 Rotating liner hanger without an integral liner top packer

Selecting and using a rotating liner hanger without an integral liner top packer (open annulus) is the best way to achieve good mud displacement when cementing and for maintaining and supplementing hydrostatic pressure continuity to the cement column after the cement job is in place. (Refer to Figure 2A-1.) The mechanical set rotating liner hanger assembly (shown in blue) on these drawings (annotated on Figure 2A-1d) consists of a tieback receptacle, a setting collar and the liner hanger. The tools shown on the sequence drawings are designed to hang and suspend a liner in a well from the lower end of an existing liner or casing string into an open-hole section below to any desired depth. After the liner is hung and the setting tools are released, this design allows rotation of the liner while conducting cementing operations until the job is completed. The hanger utilizes a slips and cone mechanical assembly to suspend the hanger from the inside walls of the outer casing string (Figures 2A-1a, -1b, & -1c) The hanger is set by manipulating and mechanically wedging the slip segments between the hanger cone and the outer casing where they can "bite" the outer casing walls and hold the cone and hanger in place. The lower end of the setting collar is mated to the top of the upper hanger body which fits inside and through the outer hanger cone and shoulders atop a radial bearing that is located between the hanger body shoulder and the top of the cone. (As annotated in Figure2A-1a.) The hanger body OD below the shoulder is slightly smaller than the cone ID so that it can fit and turn freely through the cone and bearing when rotational torque is applied to the hanger body from above. The rotating hanger body extends below the cone and through the slips cage and is threaded on the end so that it can be connected to the liner casing that is hung below. The slip cage, which is used to position the slips over the cone to set the hanger when ready, has bow drag springs and a J-slot in the lower part of the cage to prevent the slips from setting by simple up and down motion of the running string when going in the hole with the liner. The slips are positioned at the top of the cage and are connected to the bottom of the cage via metal slats that act like bow springs to allow the slips to move to an outward position when they are pushed out by the setting cone to set the hanger. The slips cannot be set until the J-lug, that is part of the hanger body, is taken out of the J-slot at the bottom of the cage to allow the slips to move up relative to the hanger body. This is accomplished by picking up and rotating the setting tools a half turn to the right to move the lug out of the J-slot, as shown in Figure 2A-1b. This is explained later in the setting sequence below. A cement collar used for landing the wiper plug and a cementing shoe at the end of the casing at the bottom of the hole complete the liner assembly.

The setting tools inside the hanger (shown in red on Figure 2A-1) connect the drillpipe/running string to the hanger assembly and are used to:

- Run the liner in the hole;
- Set the hanger;
- Rotate and cement the liner in place.

The setting tools consists of a square-shaped slip joint (a kelly) that is free to move up and down through a left-hand threaded floating nut arrangement that allows connecting the setting tools to the hanger assembly via matching threads cut inside the setting collar above the hanger body. While the kelly is free to move up and down through the nut (after the hanger has been set) it has a "no-go" shoulder at the bottom end that serves as a stop collar locator under the floating nut. The no-go shoulder at the end of the kelly allows the running string above to carry the weight of the entire hanger and liner below when the nut is mated to the threads inside the setting collar and hanger body. Connected below the shoulder of the square-shaped kelly and the spring-loaded spline is a smooth round slick joint extension that can slide up and down through a retrievable pack-off bushing positioned at the bottom of the setting collar just above the upper hanger body. The pack-off bushing has internal seal packing that acts as a dynamic seal between the bushing and the slick joint as it is worked up and down through it. The pack-off bushing also has external seal packing that seals against the inside of the setting collar. The slick joint and pack-off bushing arrangement provides circulating pressure continuity through the inside of the running string and setting tools from below the bushing through the inside of liner and all the way to the cementing shoe. This design permits circulating and cementing while allowing for up and down movement of the setting tools during the liner hanging and releasing operations. The pack-off bushing can be designed to be left in the hanger setting collar after cementing, to be drilled up later, or it can be designed to be retrieved with the setting tools. A retrievable pack-off bushing is shown on these sequence drawings. The cement wiper, shown shear-pinned at the bottom of the slick joint, is used to displace the cement out from the liner at the end of the cementing operation.

The upper part of the setting tools consists of two splines that match key slots inside the hanger setting collar. When the liner is being run in the hole (Figure 2A-1b) the lower spring-loaded spline is in the key slots to prevent the po-

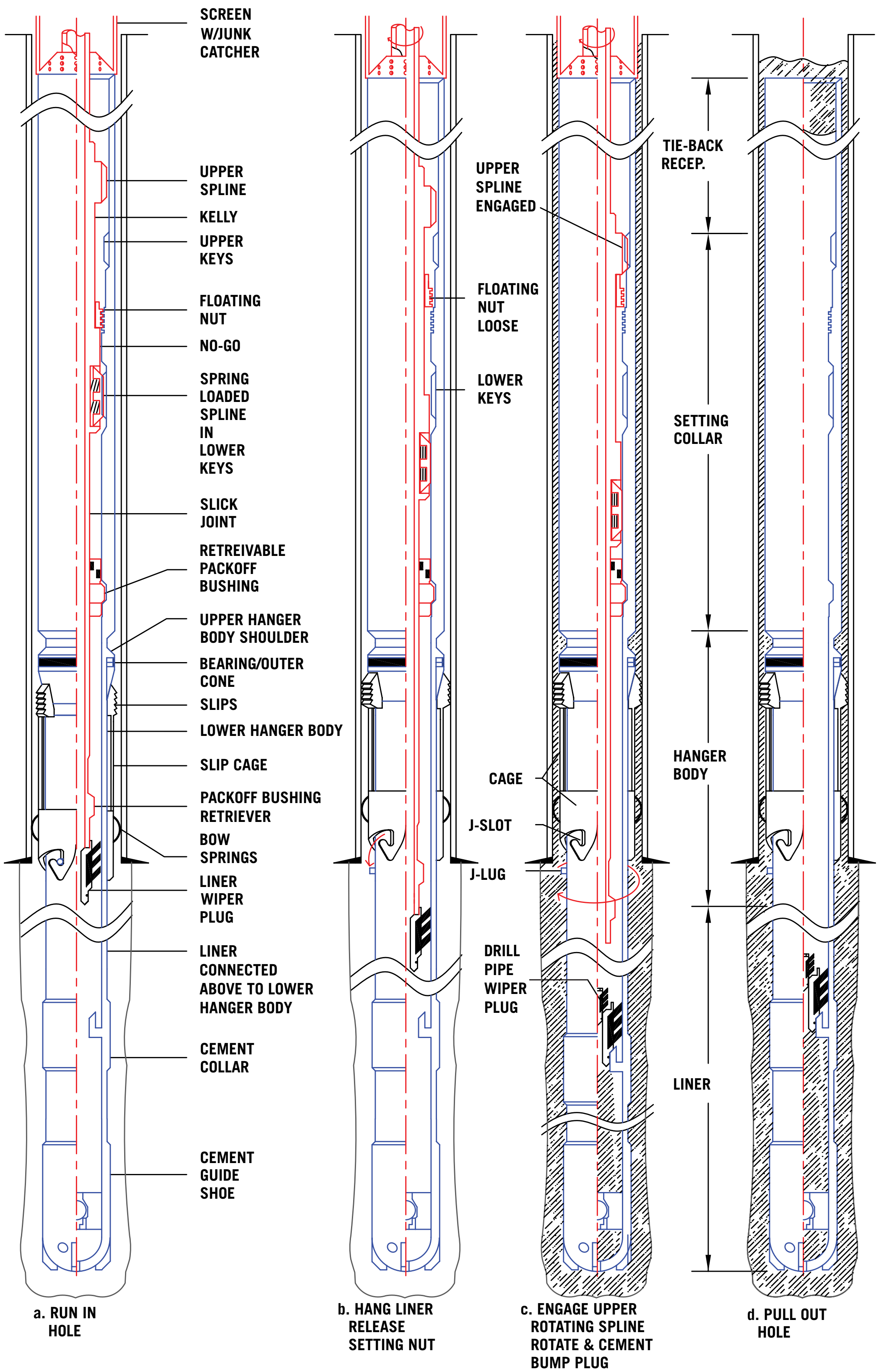


Figure 2A-1: Sequence for running, setting, and cementing a mechanical rotating liner hanger.

tential back-off of the floating nut if the liner were to try to turn relative to the setting tools, or if the running string were to be turned intentionally to help clean the bottom of the hole, or to help work the liner to bottom. As long as any liner weight is being carried by the kelly shoulder (no-go) underneath the floating nut, the lower spline remains in its key slots. The upper spline is not engaged in its key slots when the liner is being run. This upper spline will be used later to rotate the liner and will be discussed below. A combination screen and junk catcher is run above the upper spline on the setting tools and allowed to float atop the setting collar/tieback receptacle. (The junk catcher stays in place on top of the tieback while permitting the setting tool to move up and down through its center opening when performing the liner setting and releasing procedures.) This screen and junk catcher combination is important to allow free fluid entry into the tools for internal/external pressure balancing above the pack-off bushing when the liner is run in the hole. The screen also prevents junk or wellbore debris from entering or falling inside the receptacle and on top of the tools. The setting tool design allows for a liner to be run to the desired depth inside a casing string, and then through manipulation of the setting string:

- Permit setting the hanger:
- Releasing from it;
- Verifying that the release has taken place;
- Rotating the string before and during a cement job.

The design also allows for pumping both a drillpipe and liner wiper plug to displace the cement from the setting string and liner.

A hanger should always be run with a tieback polished bore receptacle (PBR) section above the setting collar atop the liner hanger. This will permit for a liner top packer or tieback string to be run after the initial cement job on the liner, if desired or necessary in the future. The liner can be run with or without differential fill flow equipment or with backpressure valves, a landing collar and cementing shoe, as may be desired or required based on operator preference and on surge pressure issues.

2A.1.1 Sequence for setting hanger, cementing liner and testing the job

After picking up the liner and running tools and going in the hole, the following steps should be used to set the hanger and to conduct the cementing operation. A good general rule to determine how high a hanger should be set (how much liner overlap to run) above the shoe of the existing casing where it will be hung, is about 300 ft. This much overlap will provide enough annular length to get a good cement seal between the casing strings without wasting too much extra liner casing or without adding any additional reduced hole size to the well than necessary.

1. Refer to Figure 2A-1a. Using predetermined measurement of the hole's depth, based on drillpipe runs, pick up the required liner length and hanger and run in the hole with the setting string. Begin searching for bottom when the shoe is within 30 ft of the expected bottom of the hole. Note that in the running position, the weight of the liner is being carried by the setting tools on the "no-go" shoulder of the kelly (shown in red) under the setting nut. In the running position the lower spring-loaded spline is in the keys of the setting collar and the liner can be turned or worked up and down without allowing the nut to unscrew. (In the running position, the upper spline is not engaged.) When the liner is within 10 ft of bottom (this may vary depending on how much fill is expected based on knowledge from drilling the hole) rig up the top drive if the rig is so equipped or pick up to a convenient height on the floor and rig up a circulating sub on a rotary rig to begin circulation while slowly reciprocating the string, to clean the hole and verify where bottom is. After circulating bottoms up and confirming that the hole is clean, determine what drillpipe subs will be needed to arrange for a convenient position at the top of the string for the cementing manifold and for a power swivel, top drive, or power tongs arrangement that will be used to rotate the liner after the hanger is set. Before setting the hanger, pick up the string to allow 5-6 ft of room between the shoe and bottom of the hole to allow space to manipulate and set the hanger.

2. If a mechanical hanger with a right-hand release J-slot slip cage (the hanger can also be designed with a left-hand release J-slot cage) is being used to set the slips, as in this drawing, the following procedure would be used for hanging the liner, releasing the setting tool, initiating rotation and conducting the cementing operation. (Refer to Figure 2A-1b.) The slips for the hanger are set by first picking up on the running string. This will cause the hanger J-lug, which is part of the hanger body positioned inside the J-slot in the lower part of the cage, to come to the top of the J-slot. Turning the setting string a quarter-turn clockwise while slowly lowering the setting string will move the J-lug out from the J-slot cage to allow disengagement between the two. Moving the landing string down further will then cause the setting cone on the hanger to slide under the slips, pushing them out to bite the outer casing to hang the liner. The bowsprings on the lower part of the cage drag against the outer casing to hold the slip cage stationary relative to the casing. This allows the J-lug to first be moved up and then out of the J-slot, as well as to allow for the slips to be wedged between the cone and the casing when the tools are next lowered to hang the liner. Once the slips are set, further downward movement of the setting

string will then transfer the liner weight from the floating nut and kelly no-go shoulder to the hanger.

3. After setting the weight of the liner on the hanger, the landing string and setting tools will be in the neutral position (free to move up and down without the liner weight) and the liner weight will be off the kelly no-go shoulder. (Refer to Figure 2A-1b.) Further downward movement of the landing string and setting tools (shown in red) will then cause the lower spring-loaded spline to move out of the key slots and allow free right-hand rotation of the setting tool, which will back-out and release the left-hand floating nut. Rotation of the setting tool without rotating the liner will disconnect the floating nut and running string from the liner. After rotating the number of turns required to unscrew the floating nut (provided by the liner manufacturer), rotate the setting string at the RPM rate you intend to use while cementing and record the torque. This value is the torque required to rotate the landing string without turning the liner. Stop rotating and pick the setting tools up past the point where the no-go and nut were carrying the weight. Picking up past this point without lifting any liner weight confirms that the liner weight is on the hanger, that the floating nut has been released and the setting string is free from the liner.

4. (Refer to Figure 2A-1c.) Lowering the setting tool until it no-goes (tags up and stops) on top of the just-released floating nut will then position the upper setting tool spline in the upper key slots inside the setting collar. In this position, with the spline engaged, the hanger body and liner can be rotated. Rig up the surface equipment and then set additional weight down on the no-go to ensure that the spline will stay engaged throughout the job, independent from setting string length changes that may occur due to temperature and pressure changes.

5. Initiate rotation and circulation of the liner to condition the mud in preparation for the cement job execution. The mud should have been conditioned for the cementing operation on the last trip with the drillstring prior to running the liner to minimize the conditioning time required with the liner in the hole before cementing. (Notwithstanding, however, it is very important to check the mud returns to ensure that the mud properties meet the needed standards for cementing and always circulate the hole past bottoms-up before commencing cementing operations.) The torque reading while rotating and circulating through the liner will be higher than when the setting string was rotated to back the floating nut out and the liner was not turning. The difference between these two torque readings is the torque caused by drag between the liner and the hole. A power swivel or other torque measuring and limiting device should be used to rotate the string, to monitor and stop rotation if the torque should rise to a level that would exceed the make-up torque limit of the weakest connection in the string and cause a twistoff. After having conditioned the mud to the desired properties, the cementing operations can begin. After the cement has been pumped, the drillpipe wiper plug is released and pumped down the drillpipe until it lands and latches into the liner wiper plug. Pressuring up behind the plugs will cause the shear pins of the liner wiper plug to break so that both plugs can then be pumped down the liner until they land and latch into the cement landing collar. Continue rotating the liner until the liner wiper plug lands to make sure that the pipe is rotating when cement is moving up the annulus. The cement slurry volume pumped should allow for the cement to fill the annulus and come up at least 300 ft above the top of the liner when the plug lands. The rotating torque should rise when cement exits the shoe and enters the open-hole vs the torque while circulating mud. This is normal because cement will have higher filtration and also have a higher coefficient of friction than the mud.

6. Refer to Figure 2A-1d. After the cement is in place and the plug has landed, stop rotating. Straight pick up of the setting string will allow retrieving the setting string and tools out of the hole without any other manipulation of the string being required. Hanging of the liner, releasing the setting tools and confirmation were carried out prior to initiating liner rotation and prior to doing the cement job. (The pack-off bushing is released and pulled from the setting collar profile by the pack-off retriever at the end of the running tools, when the retriever is pulled past the retrievable bushing on the way out of the hole. (See annotated setting tool components detail on Figure 2A-1a.) The reduced OD profile just above the no-go at the end of the retriever allows the bushing setting dogs that lock it in the setting collar profile to collapse into the reduced OD slot of the retrieving tool which then frees the bushing so that it can be pulled free.)

7. Immediately after the cement plug bumps and after checking for no backflow (plug is latched and float valves are closed and holding), the surface equipment can be laid down. Next, the setting string should be pulled a predetermined distance above the liner and the excess cement (+/- 300 ft or 3 stands). At this point, the well should be reverse circulated to the surface to remove any waste cement that may have been dragged up the hole by the setting tools. If the plan calls for leaving supplemental pressure on top of the cement column

while waiting on cement, backpressure can be held on the tubing while reverse circulating. The added pressure while reversing above the cement column will help supplement some of the in situ column pressure that may be lost due to early gelation and filtration during the time that it will take to clean out the excess cement from the annulus.

8. After completing the reversing operations (the pressure in the drillpipe and drillpipe/casing annulus should be the same when pumping stops), the string should be pulled an additional stand to ensure that the end of the setting tool is clear of any cement residue below it. If the plan is to leave pressure on top of the cement column to supplement the cement column pressure until the cement sets, provisions need to be made to trap the desired pressure in the casing above the liner while pulling the string up the hole an additional stand. In order to accomplish this operation, it will be necessary to strip one stand of pipe out of the hole while pressuring up under the annular preventer to keep the trapped pressure constant in the well. This operation will involve pre-installing a safety valve four stands below the top of the setting string and another below the third stand. After cementing and pulling three stands to the top of the highest valve, a reversing line should be installed on top of the valve. After reversing out and holding the desired back pressure the pumping is stopped and the valve is closed to trap the desired pressure. (Pressure is read on the annulus side when circulation stops.) One more stand is stripped out to the depth of the deepest valve that was installed on the drillpipe while holding pressure constant on the annulus side. The deepest valve is then closed and the valve at the top of the derrick is bled off. The stand in the derrick can be stood back. The pressure retained on the annulus can be kept constant by either bleeding or pressuring up as may be necessary while waiting and monitoring the top of cement. If no supplemental column pressure is to be held on the well while waiting on cement, the stripping operation described above is not necessary. The setting string can simply be pulled up three stands after bumping the plug, and then be reverse circulated to clean out the cement from the annulus. Next, the string can be pulled up one more stand and reverse circulated again to trap 200-300 psi pressure and shut-in on both the tubing and annulus to simply monitor the cement until it sets.

9. After waiting on cement and circulating bottoms-up the setting string can be pulled out of the hole. Next a clean out run with a bit can be made to drill the excess cement off the top of the liner. A second run with a smaller bit will then be necessary to clean out the inside of the liner to bottom. The float equipment and the liner top can be tested by pressuring up the casing. On a land well it will be necessary to run a packer in the hole to do a negative test of the liner top and shoe. This is accomplished by pumping water partway down the drillpipe to reduce the hydrostatic pressure inside the drillpipe and by using a packer to isolate the mud above it on the annulus from the well below.

    (i) First the packer, with enough tailpipe below to reach from the liner top to the landing collar, is run on drillpipe and set just above the liner top.

    (ii) Next, the packer bypass is opened, and water is pumped partway down the drillpipe displacing some of the mud in the drillpipe to the annulus and out the top of the well. The U-tube pressure at the top of the drillpipe is equal to the differential pressure between the drillpipe head and the mud head in the annulus, which is still equal to the original mud head in the well.

    (iii) The packer bypass is then closed and the U-tube pressure at the top of the drillpipe is bled off. The U-tube pressure at the top of the drillpipe is equal to what the differential pressure test will be at the liner top and at the float equipment once the packer bypass is closed and the pressure is bled off the top of the drillpipe.

    (iv) When the pressure is bled off the drillpipe, the pressure below the packer at the end of the tailpipe will then be equal to the head in the drillpipe. The head will be reduced by the water column to less than the original mud weight hydrostatic pressure used to drill the formations immediately below the top of the liner, as well as the pressure below the float equipment at the bottom of the liner. The reduced pressures at the end of the tail pipe and at the liner top, when compared to the pressure of the formations at those depths, impose a controlled differential pressure test on the cement placed between the liner and casing to isolate the liner top and in the float joints below the landing collar at the shoe. The magnitude of the differential test required or desired may be dependent on regulations or on operator choice. Using a packer to conduct the test allows the operator to test for a maximum differential up to having a full water gradient in the well.

10. On a deepwater well, a reduced differential pressure test can be done by using the subsea BOPs in the same manner as a packer to temporarily remove the riser head above the BOPs from the well below the mudline. (A

reduced differential test should only be used when the well will continue with mud in the casing. If the casing or liner set at this point will be used to complete the well with water or a light fluid internally, the differential test should be done using a packer so that a full differential test equal to a full reduced head of light fluid can be conducted.)

(i) The differential test can be done with the workstring on bottom, by pumping water down the inside to a calculated level required to reduce the hydrostatic pressure of the fluid in the drillpipe from sea level to the end of the string by slightly less than the equivalent of the hydrostatic pressure of mud in the riser. (If the riser hydrostatic pressure is 3,900 psi, and the hydrostatic pressure of the mud in the drillpipe at total depth is 12,480 psi, pump enough water down the drillpipe so that the total combined hydrostatic pressure of water and remaining mud will be reduced by 3,700-8,780 psi.) The hydrostatic pressure on the annulus from sea level to TD is still 12,480 psi, since no water was pumped into the annulus. The drillpipe pressure at the top will be 3,700 psi, which equals the difference in the U-tube hydrostatic pressure between the annulus and the drillpipe.

(ii) The negative test can now be accomplished by closing the BOPs and the choke and kill lines to isolate the mud hydrostatic pressure above the mudline from the well and then bleeding the U-tube pressure off the top of the drillpipe. (To do this test, it will be necessary to have test rams in the stack that can hold pressure from either side.) When the BOPs and choke and kill lines are closed and the U-tube pressure is released it will temporarily remove the riser mud head (3,900 psi) off the annulus side below the mudline. The pressure at the bottom end of the drillpipe is 3,700 psi less than when the well was full of mud, or 8,700 psi. The pressure at the bottom of the well just below the tubing is the same as the drillpipe, but the hydrostatic head of the mud column between the bottom of the hole and the BOPs, in the annulus between the drillpipe and casing, is reduced by the 3,900 psi of riser hydrostatic pressure above the mudline. This will create a head U-tube imbalance from the tubing side towards the tubing-casing annulus below the BOPs of 200 psi. This imbalance U-tube pressure will be acting under the BOPs as long as the rams and the choke and kill lines are closed. (The slightly higher hydrostatic in the tubing than in the tubing-casing annulus up to the BOPs will ensure that the mud column under the closed BOPs will not go on a vacuum and potentially cause confusion during the test.) The mud and water hydrostatic pressure combination in the drillpipe will establish the bottomhole pressure at the end of the test string after the BOPs are closed and the U-tube pressure is bled off to initiate the test.

(iii) The hydrostatic pressure at the end of the drillpipe, positioned just above the float equipment at the bottom of the liner and at the liner top, will be about 3,700 psi less than the hydrostatic pressure of the mud in the well before the water was pumped down the drillpipe and the BOPs were closed to conduct the test. The differential pressure test placed on the cement at both test points once the BOPs are closed and the drillpipe pressure is bled off will be the difference between the reduced internal pressure at those points and the respective pressure outside of the casing at those points. After the initial flow-back from the U-tube pressure release, flow should stop. In either the land or offshore test cases described above, after observing the well for 15-20 minutes the test is complete. No flow indicates a good test.

(iv) If the test is good, the water in the drillpipe should be reversed out by pumping into the kill line with the BOPs closed while holding back-pressure on the tubing until the water is out. (If a packer was used for the test it will be necessary to unseat the packer after reversing the water out in order to reverse the tubing completely from bottom.) After reversing the string, the BOPs should be opened and the casing can then be circulated around before pulling the test string out of the hole.

(v) If flowback from releasing the U-tube pressure from the tubing does not stop, the test has failed and the well is flowing. After shutting the well in, the same reversing process described above will still need to be used to safely get the test water and influx out of the well followed by complete circulation of the well before pulling out of the hole. If a packer was used to conduct this test, it will be necessary to unseat the packer and close the bypass after the water has been reversed out in order to be able to reverse the influx which may still be trapped below the packer. Some indication of where the influx occurred may be obtained during the reversing process as indicated by when gas, oil or water first reaches the surface. Ultimately, however, it will be necessary to use a packer to set inside the liner to determine whether the leak is at the liner top or at the shoe. When pulling out of the hole after a failed test, it is very important to monitor the trip out very carefully to make sure the well remains dead. Before running a test packer to diagnose the leak source, it will be necessary to run a casing scraper to smooth out the inside of the string where the packer will be set to remove any cement residue left from the cement job, to ensure the packer will set properly. Depending on the results of the test, a repair would follow either by squeezing the liner top or by drilling out the shoe and testing the openhole, which may require a squeeze job if the leak-off is low. (Special note: When conducting either the land or deepwater differential pressure tests described above, water is never pumped outside the test string, and that kill weight mud always fills the annulus between the test string and the outer casing and liner all the way to the bottom of the well. Essentially this test method allows the use of a kill string in the well during these critical tests which greatly reduces the risk of a well control problem when testing a cement job against a potential high flow capacity zone.)

11. If the initial tests following the cement job are good, or after making repairs if the initial tests failed, and if a liner top packer is to be set in the well, the next step would be to run a polishing mill (smooth file milling surface) to clean out and hone the inside of the receptacle and to dress off the top. The polishing mill is designed to remove any burrs or cement debris from the receptacle surfaces that could damage the stinger seals. The liner top packer with a seal stinger below would then be run and set using a simple compression setting tool. The liner top packer should have a tieback receptacle on top which could be used in the future to install a tieback if a leak were to develop in the casing above. If the liner top packer was set because the liner top leaked but could not be squeezed, then the packer should be tested to ensure that the liner top leak has been sealed. If the liner top packer was set as an extra barrier on top of a liner that tested, it is not necessary to retest the packer installation.

12. If the liner was set to drill ahead, then the last step in this sequence is to drill out the shoe and to conduct a leak-off test prior to drilling ahead. The results of the leak-off test will then establish the formation fracture gradient limit for the next drilling interval.

2A.2 Rotating liner hanger with integral liner top packer or expandable hanger application

In a liner cementing case where annular gas flow following a cementing operation is not a risk, it is acceptable to use either a rotating liner hanger with an integral packer or an expandable liner hanger to set the liner. Either of these choices result in cutting off the hydrostatic head of mud above the liner top from the column of cement below when the integral packer is set in case of the rotating hanger, or when the upper part of the expandable hanger is expanded, and seals off against the inside of the outer casing string.

2A.2.1 Rotating liner hanger with integral liner top packer

If a mechanical set rotating liner hanger with an integral liner top packer is selected, the same setting, releasing, rotating, circulating, and cementing procedures are used as in the case without the integral packer described above in paragraph 2A.1.1. If a hydraulic set hanger is selected instead, (shown on Figure 2A-2), then only the initial setting procedure to position the slips over the hanger cones would be modified to use a hydraulic piston tool built into the hanger body. Figures 2A-2a & 2A-2f show and label the hanger assembly (in blue), including the tieback receptacle, setting collar, integral packer and hydraulic hanger. Figure 2A-2a shows the running and setting tools in red. The hydraulic shifting tool is activated by dropping a ball that will land and seat in a ball catcher assembly so that pressure can be applied inside the string to shift a hydraulic piston built into the hanger assembly. The tool shift moves the slips over the cone, instead of having to un-J the hanger from a slip cage. This is shown on Figure 2A-2b. After the liner is hung by setting its weight on the slips, the setting tool is moved down, also shown on Figure 2A-2b, so that the lower spring-loaded spline can be moved out of the lower keys, to allow right-hand rotation of the setting string to release (unscrew) the floating nut. After releasing the floating nut, raising the setting string up above the point where the liner weight was carried by the running string confirms that the setting tools are free from the liner. Next, as shown on Figure 2A-2c, lowering the running string back down until it no-goes on top of the loose setting nut, then positions the upper spline into the upper keys so that the liner can now be rotated. The well can now be circulated to condition the mud and to conduct the liner cement job. In order to run an integral packer with a liner hanger, the hanger body assembly is modified by adding a compression-set packer above the hanger and below the setting collar and tieback receptacle (as shown on all of the drawings). The running tools (shown in red) are also modified by adding a compression setting tool which consists of a set of spring-loaded setting dogs positioned on the upper part of the setting tool above the upper spline and below the floating screen and junk catcher. (Shown and labeled on Figure 2A-1a.) The spring-loaded setting dogs remain retracted and stay inside the tieback receptacle during all of the setting string operations until the cement job is completed, the wiper plug is landed (shown on Figure 2A-

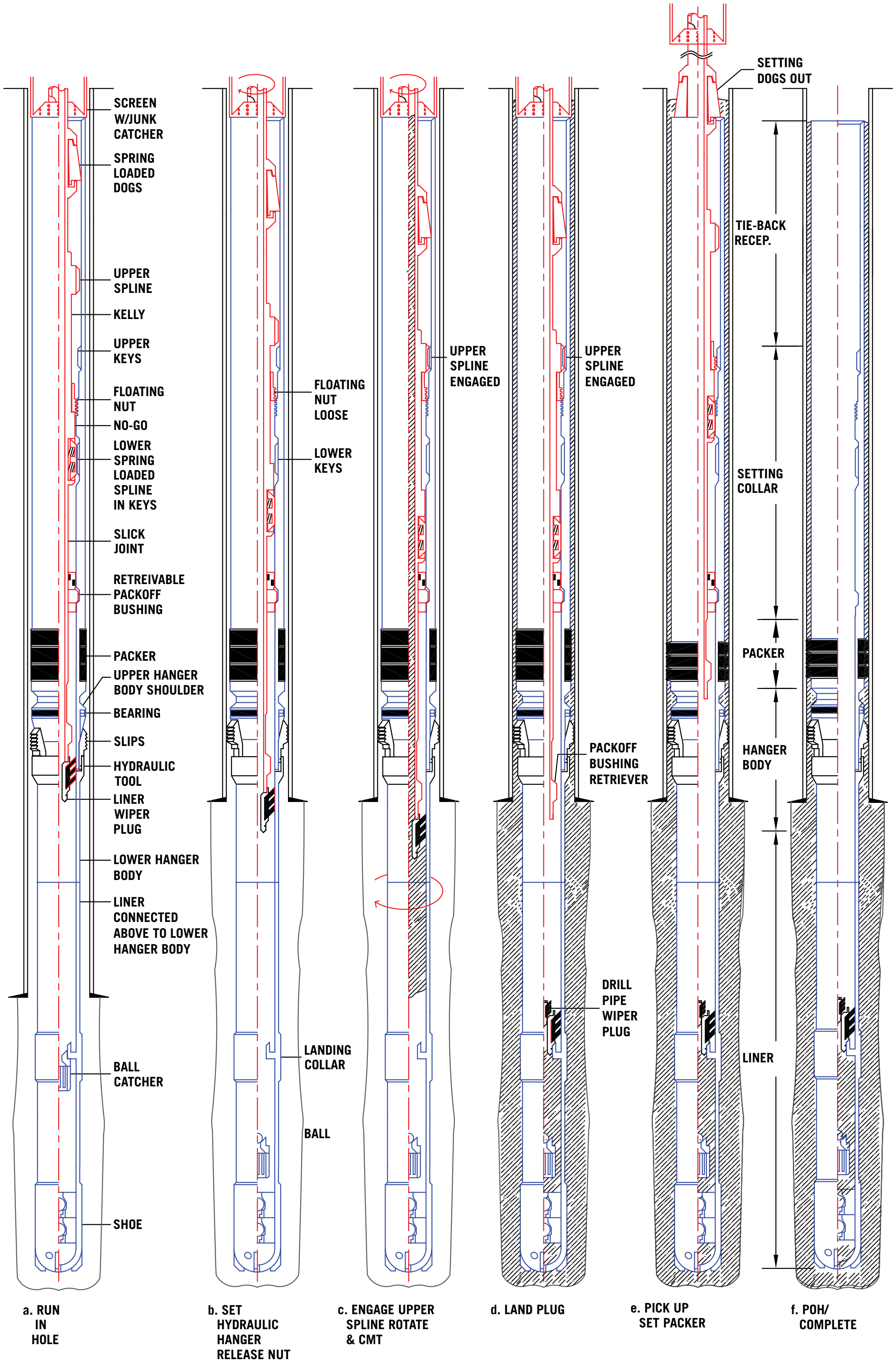


Figure 2A-2: Sequence for running, setting and cementing a hydraulic set rotating liner hanger with an integral liner top packer.

2d) and the floats are tested for backflow. After confirming the floats are holding, the setting tool is pulled up until the setting dogs clear the top of the receptacle. When the setting dogs clear the top of the receptacle springs behind the dogs will pop them out as shown on Figure 2A-2e. After the dogs are in the out position, moving the setting tools back down will cause the dogs to tag-up at the top of the receptacle. Applying a downward load at the top of the tieback receptacle with the setting string will then compress and set the packer below as shown on Figure 2A-2e. After setting the packer and pulling the end of the setting tools to the top of the tieback receptacle, the excess cement above the hanger can be reversed out to save a trip to drill excess cement out later. Clean-out of the inside of the liner and subsequent testing will be the same as in the non-integral packer liner hanger case in paragraph 2A.1.1.

2A.2.2 Expandable hanger applications

If the choice is to use an expandable hanger for this application, there are several manufacturers with slightly different designs available. Check with the manufactures for details on features and specific procedures for the individual designs. The following description is for a typical design available from one service company.

An expandable hanger is run in a well using a drillpipe running string in much the same manner as when a liner with a conventional hanger is run. When a conventional hanger is run and set in a well, the setting tool's design provides the means for delivering and hanging the liner, cementing it and then retrieving the tools from the hole when the job is completed. The big difference in the case of an expandable hanger is that the running tools (shown in red on Figure 2A-3), used for setting the hanger, do more than deliver the hanger. These tools also serve to hydraulically and mechanically expand, or stretch, the diameter of the top part of the hanger out against the internal diameter of the casing that the liner is being hung in. The top of the stretchable, or "expandable", liner hanger (shown in blue on Figure 2A-3) has external embedded slip-like serrated plates that serve to "bite" the inside surface of the outer casing when they are forced out against it. The external diameter of the expandable section of the hanger also has a series of elastomer seal rings around it to serve as pressure pack-offs when the section is expanded out against the inside surface of the outer casing string. The grooved slip-like plates and the seals serve to transfer and hang the liner weight and form a seal against the ID of the outer casing string. The tools, as annotated on the Figure 2A-3a and 3b, starting from the bottom up are:

- Cementing shoe;
- Landing collar;
- Liner wiper plug attached to the bottom end of the slick stinger;
- Slick stinger which forms a dynamic seal through the pack-off bushing below;
- Drillable Pack-off bushing and rotating spline above;
- Mandrel and running threads - to connect the running string to the hanger and liner. The mandrel carries the weight of the liner and also provides an upward reactive force below the hanger when the multi-piston tool pushes down on the expander to expand and set the hanger;
- Expandable Hanger section-outside (Blue);
- Expander/tieback or "plunger" that is used to expand the top of the hanger (Blue);
- Multi-piston hydraulic tool: This tool is used to provide the force necessary to push the expander/tieback down into the top of the hanger to cause it to expand out (swell out) against the outer casing. The multi-piston hydraulic tool consists of multiple pressure chambers (two shown in this drawing) that form a piston and cylinder arrangement between the inner mandrel of the running tools (shown in red) and an outside sliding sleeve (shown in green). The piston surfaces (green) are part of the outside sliding sleeve, as labeled on Figure 2A-3c. The cylinders (pressure chambers) are formed by the space between the mandrel and the outside sleeve above the pistons. The chambers below the pistons are vented to the outside of the tool. When pressure is applied internally to the running string, it enters the pressure chambers through ports in the mandrel wall and acts down on top of the pistons. The downward force then drives the sleeve down while venting the fluid below the pistons to the wellbore. The forced downward movement of the outer sleeve pushes the expander tieback into the hanger which causes it to swage out (expand), seal and hang the liner to the outer casing. The mandrel, which forms the cylinder portion of the hydraulic piston tool, is attached to the running threads below the hanger by a collet release nut which provides an opposite and reactive force to the expander tool when it is being forced down into the top of the hanger. (This is known as a push/pull tool.) After the hanger is expanded, the running string is lowered to set the liner weight on the hanger. This will allow the threaded collet back-out nut, which is mated to the running threads, to be in the neutral position (without tension or compression). Right-hand rotation of the string will now allow the mandrel to unscrew and release the back-out nut from the running threads. The back-out nut is designed so that it cannot be unscrewed from the running threads until the hanger has been set. The running tools are prevented from rotating and releasing the back-out nut from the running threads by a set of locked dogs that are shear-pinned to the mandrel. The pins on the locked dogs are designed so that they will not shear until a predetermined reacting

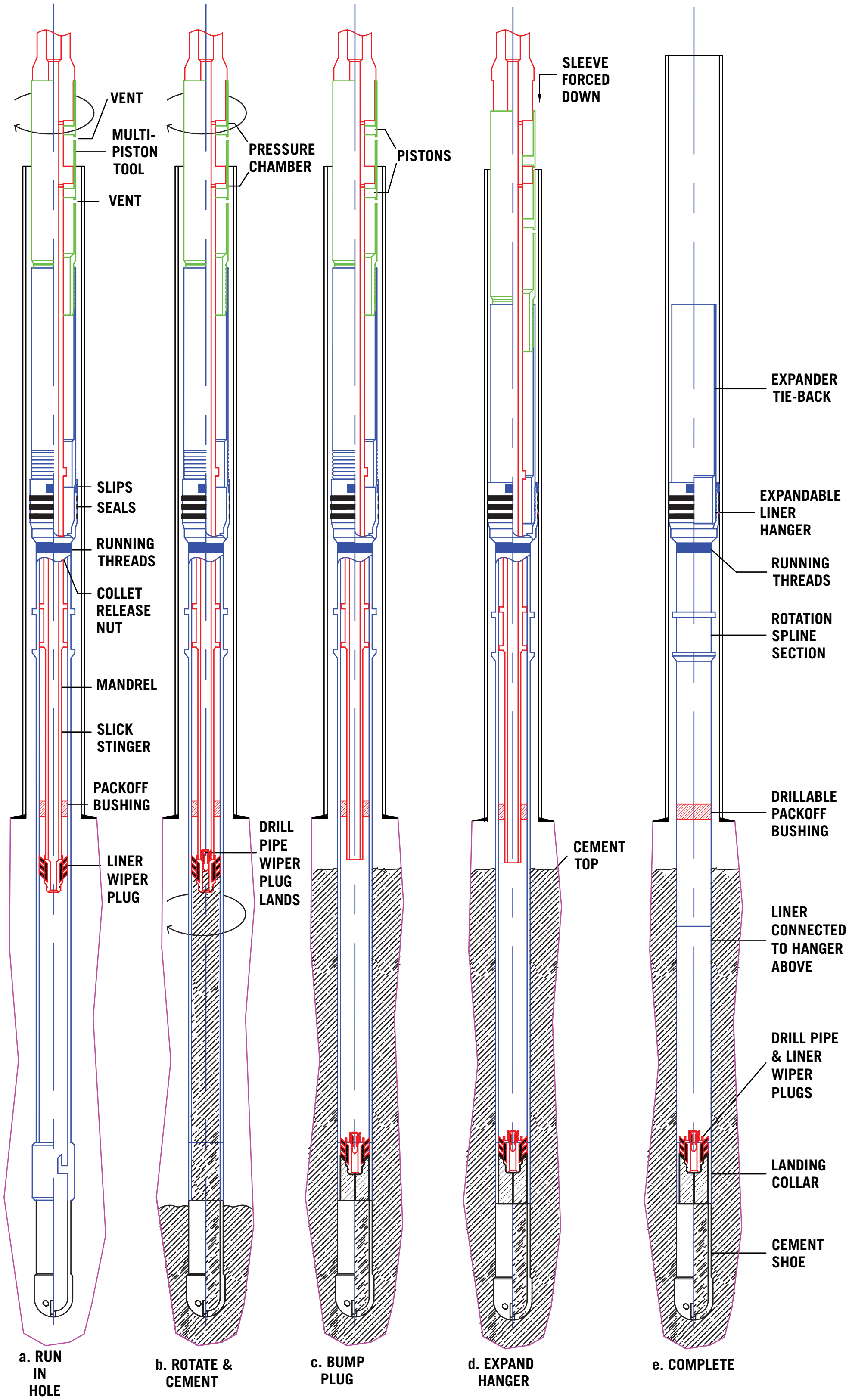


Figure 2A-3: Sequence for running, cementing, and setting an expandable liner hanger.

pulling force on the mandrel is reached, when the multi-piston tool is stroked to force the expander into the hanger to expand and set it. After the pins are sheared, the dogs collapse and the mandrel can be rotated to unscrew the back-out nut and release the running tools from the hanger. Disconnecting of the back-out nut does not happen until the cement job is completed, the plug bumps and the hanger is expanded. This procedure for disconnecting the nut, only after the liner has been expanded and set, is necessary to allow rotation of the liner while circulating and cementing until the plug bumps without fear of disconnecting form the hanger prematurely.

2A.3 Sequence for running and cementing expandable hangers

The following procedure should be used to run and cement this type of liner hanger system:

1. Refer to Figure 2A-3a. Liner is run to bottom with the drillpipe setting string. When the liner is within 30 ft of bottom begin circulation while working and rotating the pipe until bottom is located. Position the shoe about
   5 ft off bottom and continue rotating and circulating the hole to condition the mud prior to cementing. The mud should have been conditioned to the desired properties on the last clean-up run with the drillpipe to minimize the time required with the liner in the hole. Check the returning mud flow properties to ensure that they are in the desired range and adjust if necessary. At minimum, always circulate the well past bottoms-up before commencing with the cementing operations.

2. Continue rotating the liner and pump the cement job. Displace the drillpipe wiper plug, which will land on the liner wiper plug and then be pumped together down the liner until they land at the landing collar (Figures 2A-3b and 2A-3c).

3. Stop rotating just before the plugs reach bottom. (Note that with this equipment the running string, the setting tools and the expandable hanger and liner remain connected throughout the cementing procedure.) The running string is not separated from the hanger and liner until after the cement job has been done, the hanger has been expanded and the running tools have been released from the running threads.

4. When the wiper plug lands at the landing collar, pressure up against it to stroke the multi-piston hydraulic tool. Expand the hanger (Figure 2A-3d). F(or a description of how the tool works, see the final bullet in Section 2A.2.2 on the multi-piston hydraulic tool.)

   If the wiper plug should fail to hold pressure after it lands, there is a back-up system to allow pressure to be applied to the multi-piston tool by dropping a steel ball that will land and seat in a ball catcher sub in the running tools to allow setting the hanger.

5. When the hanger is set and the liner weight is landed on the hanger, the setting tools are released from the running threads by right-hand rotation of the running string. The tools can then be pulled out of the hanger. Reverse out to clear the top of the hanger of any cement that either intentionally was brought past the hanger or that may have channeled past the intended cement top below the shoe of the casing in which the liner was hung. Note that the drillable pack-off bushing remains in the lower part of the hanger body and will be drilled up later on a clean-up run or when the liner shoe is drilled out.

6. The hanger can now be pressure tested before pulling the tools, if desired.

7. Refer to Figure 2A-3e. The hanger is set and the expander section, used to stretch the hanger out, remains wedged and locked atop the hanger to serve as a tieback receptacle in the event that the liner may need to be tied-back to the surface.

When doing a cement job on a liner using an expandable hanger, it is important to either leave the cement top short of the casing shoe below where the hanger is being set (as shown on the drawings) or to bring cement above the hanger. This is so that fluid will not be left trapped behind the liner, below the expanded hanger and above the casing shoe, where later heating due to producing or deeper drilling operations can cause the fluid to expand without having a relief point and result in collapse of the liner. Cementing past the liner top or leaving the cement short of the casing shoe where the liner is being set is an operator's choice and both approaches are being used today. The only risk to bringing the cement above the hanger is the potential for cementing the tools in the hole while trying to expand the hanger or while releasing the running tools if there is a problem encountered with the expanding process. Alternate back-up systems are built in to these tools so that they can be quickly released from the hanger if difficulties are encountered.

2A.4 Running, cementing, and landing a tieback casing string

When a liner is run in a well for completion purposes or for drilling deeper, and the casing above the liner is not rated for the pressures that will be encountered when the well is producing or drilling ahead, it is necessary to run a casing tieback from the top of the liner to the surface. The tieback is

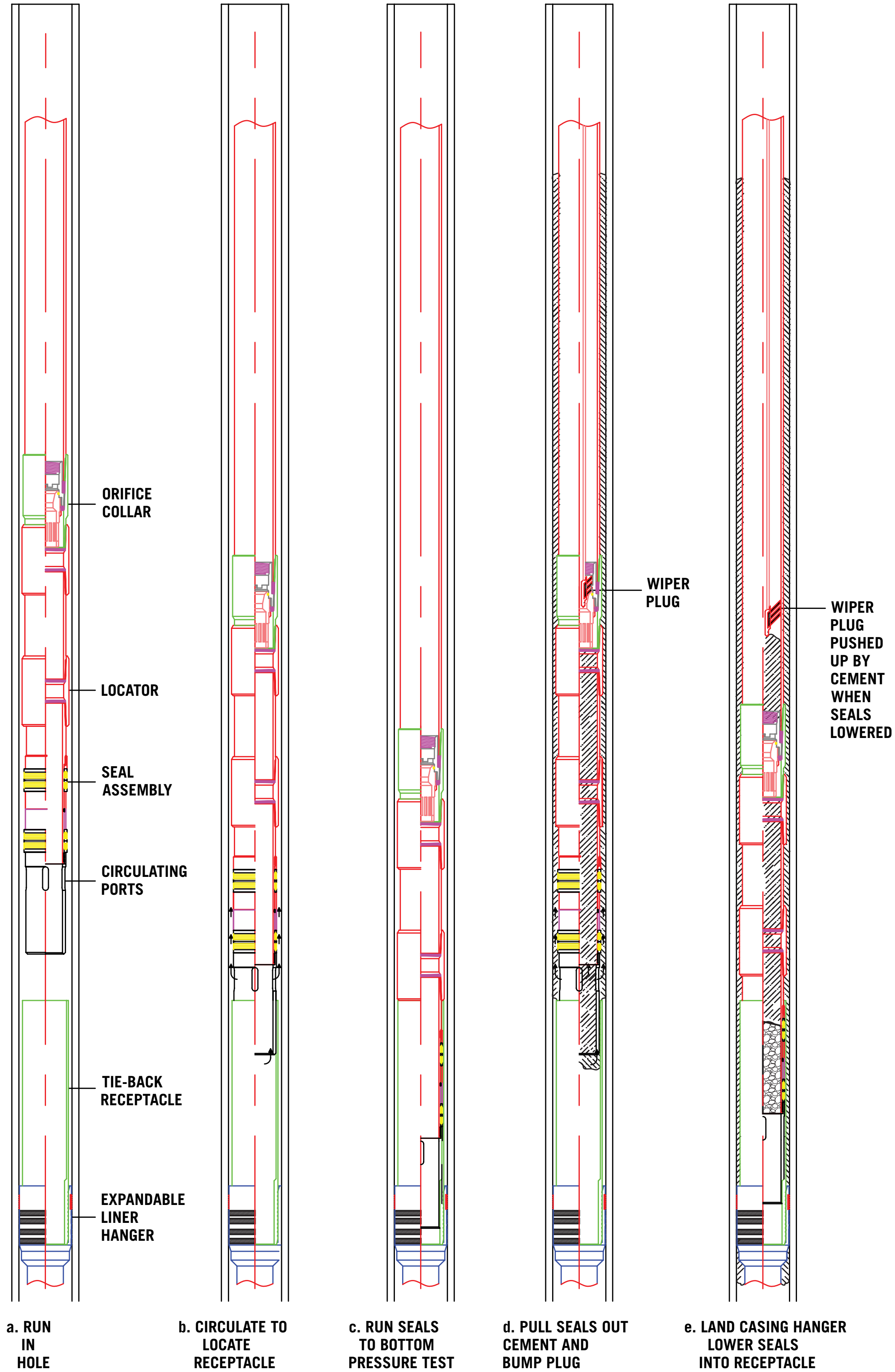


Figure 2A-4: Sequence for running, cementing and landing a casing tieback string.

necessary in order to complete a fully rated string for the intended service. On occasion a tieback string may also need to be run to repair a leak in an upper casing string above where a liner with a tieback receptacle was installed below the leaking casing. Essentially a tieback string is an upward extension of an existing casing string for the purpose of providing a higher rated full string of pipe to the top of the well where one does not exists.

There are several manufacturers of this equipment and their tools and procedures may vary; however most of the designs basically involve joining two strings of pipe together via the use of seals inserted into a polished/honed receptacle. When the two sections are joined, cement or a latching mechanism is used to permanently hold the two pieces of pipe together to form the continuous string. The following procedure is one such way of accomplishing the tying together of a liner and a tieback casing string.

2A.4.1 Designing a tieback string

Figure 2A-4 shows a sequence of drawings that will be used to describe how a liner tieback string should be designed and the procedure that should be followed to do the job right the first time. (Refer to Figure 2A-4a.) A tieback string which is to be connected to an existing tieback receptacle atop a liner, previously cemented in a well, will generally consist of casing with a wellhead hanger at the top and a seal assembly (stinger) on the bottom. The stinger of a given length (depending on the length of the receptacle), will have several unitized seal sections with an open bottom entry guide shoe with an outside beveled surface at the bottom of the stinger. The top of the seal assembly will have a locator (shoulder) above the seal section which is used to help position the seals relative to the receptacle during the joining procedure. The bottom of the stinger will have a blank section below the lowermost set of seals with circulating ports located a short distance below the seals. The seal stinger should be shorter than the length of the receptacle, so that when landed after cementing, the end of the stinger will be left short of the bottom of the receptacle. The locator at the top of the seals should also be left short of tagging the top of the receptacle when the tieback is landed in the wellhead. Not tagging the receptacle with either the locator or the end of the stinger ensures that the casing can be landed at the surface, "hanging free", with its full buoyed weight. A non-latching orifice landing collar (landing collar with a ported flapper backpressure valve) should be installed within a couple of joints above the top of the seal stinger. The two joints above the seals serve as float joints, so that when the wiper plug lands at the orifice collar above, the two joints below it will hold cement and the contaminated mud that the wiper plug squeegees off the inside casing walls when it is pumped behind the cement. This will ensure that the cement pumped below and around the seals, and left in the tieback and outer casing annulus, will be clean and uncontaminated when the seals are lowered into the receptacle and the tieback is installed.

The receptacle portion of the tieback is run as part of the upper setting collar section of the liner hanger below. The top of the receptacle is beveled on the inside to serve as an entry guide for the end of the tieback stinger when it is lowered into the receptacle. In general, the length of the tieback receptacle and the stinger on a land well or surface landed non-subsea wellhead will be about 10 ft. The stinger should be at least 12 in. shorter than the receptacle and the guide section below the lowest set of seals at the end should be 18 in. long. In the case of a subsea well tieback, the length of the receptacle should be at least 30 ft long and the stinger should be 4 ft shorter. The bottom guide section of the stinger should also be at least 5 ft long below the circulating ports under the last set of seals. These longer ranges will allow more tolerance for spacing the seals in the receptacle and also help contend with heave when cementing the tieback. When landing the hanger, being even 10 ft off on the measurements or having 5 ft of heave, (which would be excessive) would still allow landing the string with at least 15 ft of seals in the receptacle. When cementing, the longer guide at the end of the stinger below the lowest set of seals will allow for the end of the stinger to stay in the receptacle while cementing, without fear of the lower most seals inadvertently entering the receptacle from a downward heave motion of the rig even when experiencing as much as 3 ft of net heave. (More than 3 ft of heave is rare with modern active heave compensation systems in use today.) Having a 5-ft section of blank stinger below the lowermost seals will allow the stinger and receptacle to act like a slip joint during these critical operations within the limits of the moderate sea conditions. If conditions exist where heave is beyond the limits allowed by the stinger design, the job should be postponed until conditions are acceptable to do the work safely.

2A.4.2 Procedures for running and cementing a tieback string

An important first step before running any tieback should be to run a polishing mill to clean out the receptacle and to remove any burrs or nicks from both the inside of the polished section of the receptacle, and the top of the beveled entry guide. This will ensure that the seals will not be damaged when they are inserted into the receptacle when the cement job is completed. Circulate and condition the mud to the desired properties for doing the cement job before pulling out of the hole to pick up the tieback string. The polishing mill run will also provide the best measurements needed to make up the tieback string for landing the casing at the surface with the seals in the desired position relative to the receptacle. The pipe stretch (elongation) due to the free-hanging weight for one size drillpipe when doing the mill run and the casing stretch for a string of one size casing for the tieback and the stinger will be the same with either string. Pipe stretch due to hanging weight for two strings of the same length made of the same material (steel) with the same density, suspended in the same density fluid, will stretch the same amount independent of the size of the tubes as long as each string is of one size all the way. (i.e., 10,000 ft of 5-in. 19.53-lb/ft DP and 7 ⅝-in 29.7-lb/ft casing freely suspended in a well with the same density mud will stretch the same amount). One-size strings run in a well have the buoyant force of the fluid in the well acting at the bottom end of the string. For tapered strings with a cross-over to a different casing size, a more rigorous analysis is required to calculate the net strain for each hanging casing and drillpipe string. The reason for this is that the buoyancy force from the fluid in the hole will act both at the bottom of the string and on the area differences that occurs at the crossover to a different size pipe. The stretch differences may be in the range of a few inches in most cases, but it is always best to do the analysis to make sure. Computer programs are available in the industry to do this analysis. (Example: 10,000-ft string of 5-in., 19.5-lb/ft drillpipe hanging in a well with 14-ppg mud will stretch 44 in. A 10,000-ft string of 7 ⅝-in., 29.7-lb/ft casing hanging in a well with 14-ppg mud will stretch the same amount as the drillpipe. A string of 5,000-ft, 7 ⅝-in. 29.7-lb/ft x 5,000-ft, 7-in. 26-lb/ft casing hanging in the same well with the same density mud will stretch only 41 in.)

The following procedure should be used to run, cement, and land the tieback string on a land or surface wellhead landed string. (Refer to Figure 2A-4.)

1. The seal stinger, locator, float joints, orifice collar and tieback casing are picked up at the surface (use the measurements from the mill run to space out the wellhead hanger relative to where the seals will be positioned in the receptacle) and run in the hole to within 15 ft of the top of the receptacle (Figure 2A-4a).

2. Install a circulating sub at the surface above the rig floor.

3. Initiate circulation down the inside of the tieback as it is slowly lowered into the well, until a pressure increase is noted as the end of the stinger enters the top of the tieback receptacle. Lowering the stinger further will also result in a second pressure increase as the circulating ports enter the top of the receptacle. These measurements can now be used to compare with the spacing requirements for landing the casing in the wellhead hanger with the seals in the right position inside the receptacle after the cement job is completed. (Refer to Figure 2A-4b.)

4. Stop circulation and open the valves at the top of the tieback (to avoid a pressure lock) and lower the casing to insert all of the seals into the receptacle until the locater tags at the top of the receptacle. (Refer to Figure 2A-4c.)

5. Pressure up inside the tieback to test the seals, release the pressure, and pull the seals until only the bottom seals are still inside the receptacle.

6. Pressure up again, to a low pressure, and pull up slowly to determine when the seals have cleared the top of the receptacle and the pressure bleeds off. (These tests will ensure that the receptacle is not damaged or obstructed in any way that would prevent them from being installed as intended after the cement is in place.)

7. If the casing will be landed at the surface using a mandrel casing hanger, install and space it out at the surface so that it can be landed properly after the cement job is done. (The hanger should be landed with the locater left short of tagging the top of the receptacle so that the tieback will be hung with its full buoyed weight.) (Refer to Figure 2A-4e.)

8. Rig up the cementing manifold, circulate the tieback with the end of the stinger sitting just inside the receptacle, check the mud for desired properties, and circulate past bottoms up.

9. Conduct cementing operations and pump the non-latching wiper plug behind the cement until it lands at the top of the orifice collar. (Refer to Figure 2A-4d.)

10. Release the pressure from the manifold and lower the stinger until the hanger has landed in the wellhead and the seals are in place inside the receptacle. The orifice collar will minimize U-tube flowback by the heavier-than-mud cement on the annulus until the first set of seals enters the receptacle. After the seals are in the receptacle, the non-latching wiper plug will be further displaced up the tieback by the trapped fluid below it in the float joints as the seals are inserted into the receptacle (Figure 2A-4e). This displacement of cement from the float joints through the ported orifice collar avoids creating a pressure lock from the piston and cylinder effect caused by the insertion of the seals into the receptacle. Note that when the hanger is landed, both the locator at the top of the seals and the end of the stinger are short of tagging the top of the receptacle and the bottom of the receptacle respectively, as intended. If the tieback was installed with plans for drilling ahead it should be tested after drilling out the tieback float joints and running to bottom to drill out the shoe.

In the case of a subsea wellhead, the procedure for running and cementing a tieback will be changed slightly as follows: The measurements from the mill run will still be used to space out the mandrel hanger relative to the position of the seals when they are inserted into the receptacle. The amount of casing run after picking up the seals should be of the length required to land the hanger with the seal locator short of the receptacle at least the same distance as the amount of heave being experienced during the job. The running string to land the hanger is then picked up and the tieback is run in the hole. The procedure for locating the receptacle is the same as in the land case. The stinger is run short of the expected top of the receptacle and circulation through the string is started (Figure 2A-4b). The string is lowered until the end of the stinger enters the top of the receptacle with a noted pressure increase. At this point the measurements for the relative position of the hanger to the seals and receptacle can be confirmed. Lowering the seals further while still circulating will cause the circulating ports below the lowermost seals to be partially restricted as they enter the receptacle, giving an additional indication that the stinger is in the receptacle. At this point, circulation is stopped and the valves at the top of the tieback casing on the surface are opened (to avoid a pressure lock). The seals are lowered into the receptacle to check for any obstructions in the tieback receptacle until the hanger tags the wellhead profile. The distance that the hanger was lowered from when the stinger first entered the receptacle until the hanger tagged on the wellhead will determine how much of the seal section will be left inside the receptacle when the hanger is landed. (For a subsea well, the mandrel hanger will need to be landed in the wellhead profile before the seal locator at the top of the seal section ever reaches the top of the receptacle so that the casing will hang with its buoyed weight when cemented in place.) After landing the hanger, pressure up inside the string to test the seals. Release the pressure and pull the seals out until the last set is still in the receptacle, then apply a low pressure inside the string and pull the string until the pressure bleeds off. This confirms the top of the receptacle relative to the lowermost set of seals and the hanger. If all of the measurements check-out, circulating the well, checking the mud, circulating bottoms-up and the cementing procedure can follow. If the measurements are off, so that the hanger tags the wellhead before the seals enter the receptacle, this means that the amount of casing tieback picked up is too short between the end of the seals and the hanger. If the hanger cannot be landed because the seals take weight prior to the hanger reaching the wellhead, this means that the length of the tieback from the top of the seals to the hanger is too long. The other possibility if this occurs may also mean that there is an obstruction in the well. At this point the tieback will need to be pulled at least to where the hanger is connected to the casing. Diagnostic and corrective action would follow.

To begin the cement job the end of the stinger would be positioned as in Figure 2A-4d, with about half of the blank end section below the lowermost seals inside the receptacle. After circulating bottoms-up, the cement job would be done as in the land case, followed with a non-latching wiper plug which will be landed in the orifice collar about two joints above the top of the seal locator. After the plug bumps, pressure is bled off the drillpipe and the string can be lowered to insert the seals into the receptacle as the hanger is moved into position and landed in the wellhead. The lowering and inserting of the seals into the receptacle will cause the fluid inside the seal stinger section (cement) to be displaced up into the float joints section of the tieback (piston and cylinder effect). The displaced fluid will be forced through the opening in the orifice collar at the top of the float joints which will move the wiper plug up to allow space for the cement (Figure 2A-4e). When the hanger reaches the wellhead profile and is landed, the seal locator will be left short of the top of the receptacle, leaving the casing tieback fixed at both ends with its full buoyed weight after the cement sets.

2A.4.3 Temperature change considerations

The effect of temperature changes over the length of a tieback string (thermal expansion or contraction) during and after its installation and cementing operations should be addressed as part of the planning process. When the drillpipe or tieback is run in the hole, which has not been circulated for more than a day while running the casing, it will quickly be at the same temperature as the wellbore fluids, which should be fairly close to the near wellbore temperature gradient as changed from undisturbed gradient by the drilling and other circulation operations. If the temperature curve profile for the drillpipe when it was first run in the hole with the polishing mill is close to what it is when the tieback is run in the hole, then the thermal effects would be the same for the two strings. (This will depend on circulating time prior to the runs and other factors such as rate and inlet temperatures of the fluids being pumped.) If the profiles are similar, this means that picking up the same amount of casing as the length of the drillpipe would be indicated. If this assumption is correct, then it can be verified when the casing and stinger is run in the hole and the top of the receptacle is located. Being 10°F off in this temperature assumption over the entire length of a 10,000-ft string will change the length by 8 in., which means that an even bigger difference can be tolerated because of the stinger lengths being used. When circulation is started prior to, and as part of the cementing process, the fluid being pumped from the surface tanks down the drillpipe and around the stinger begins it journey at surface temperature. As the fluid goes downhole, it will begin to pick up heat from the surroundings as it simultaneously does heat exchanging with the gradient source. As the circulation process continues, the effect will be that the bottom half of the circulating string will be further cooled

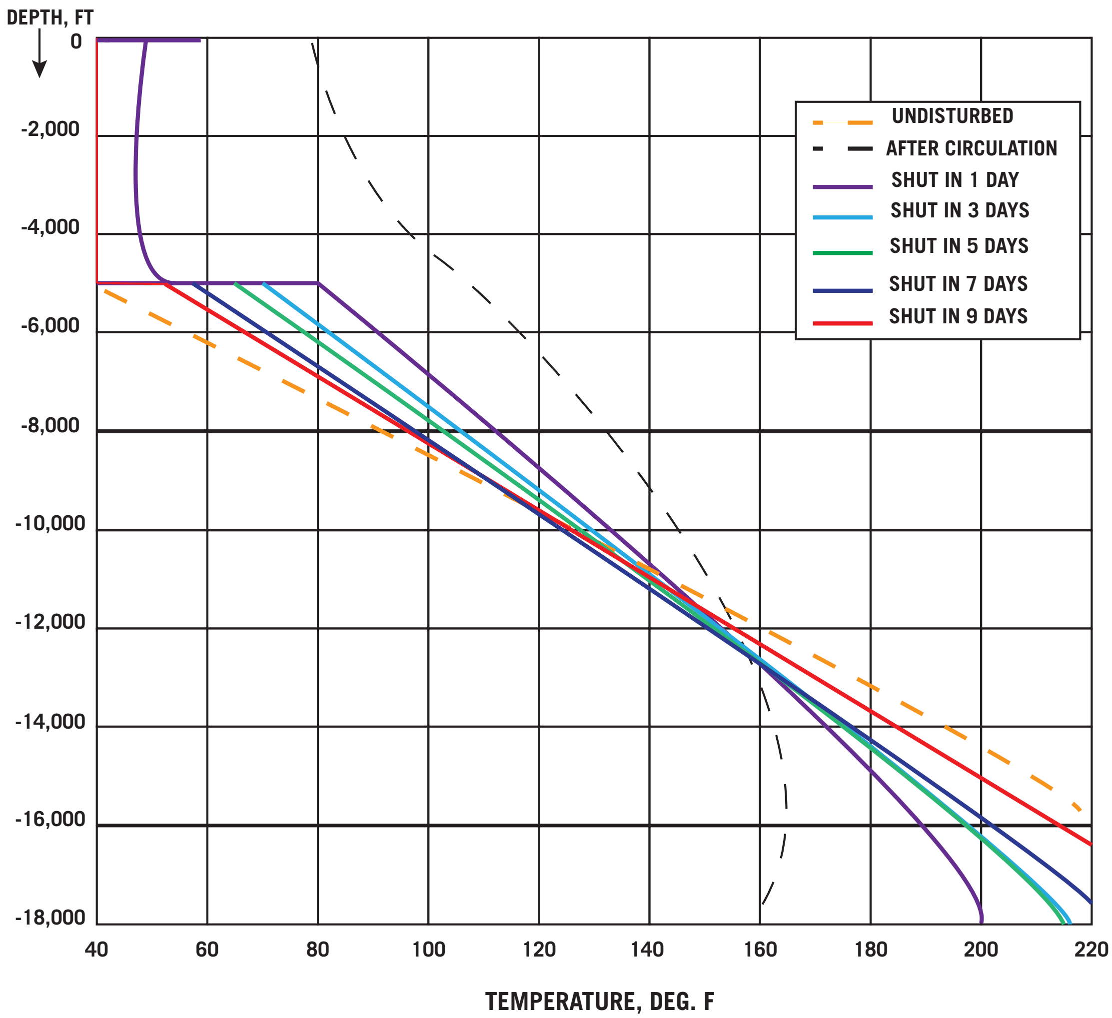


Figure 2A-5: Deepwater well shut-in temperature profiles after 8-day circulation example.

and the top half will be further heated relative to the static temperature of the well. The longer the well is circulated, the more this cooling of the bottom and heating of the top occurs until at some point in extended time the temperature profile would reach equilibrium. This typically will not be reached in the duration time of a cement job. Throughout the circulating process, however, it is noted that for land wells where the temperature gradient is fairly constant with depth (example: 1.5°F /100 ft), the average circulating temperature increase for the top half of the string and average circulating temperature decrease for the lower half of the string relative to static is about the same. What this means is that the temperature elongation of the top part of the circulating string due to heating and the shortening of the lower part due to cooling will mostly offset each other and the net effect is that there will be no measurable length change due to temperature during installation. After the tieback is landed, it will eventually go back to the static temperature which was the starting point before the circulation process began. Temperature changes before the cement sets will change the length of the string only slightly, since cement will only take a couple of hours to set. Of more significant concern is what can happen after the tieback becomes fixed at the wellhead and at the top of the set cement. The upper half of the earth surrounding a long-duration drilling well will be heated for some distance around the well structure from many months of circulating hot mud to the surface. Before production starts, this upper half of the well where the casing strings are fixed but uncemented will experience a net cooling effect as the surrounding formations go back to the natural temperature gradient. Stimulation treatment or pumping into the well for other reasons will also cool this section of the well. These are all conditions that will affect the loads in the strings and should be considered in planning and designing the pipe and connections in the upper part of these strings. (Chapter 10 of this book entitled Load and Stability Analysis of Casing Strings provides the necessary information and methods to conduct a comprehensive analysis of all fixed casing strings in a well as impacted by pressure and temperature changes over the life of a well.)

For deepwater subsea well cases, the issues described above are further complicated because the normal temperature gradient of the well system from the rig to the mudline is a cooling gradient and then becomes a heating gradient from the mudline to TD. Like in the land case, drilling for many months will cause the top part of the near wellbore very cold formations below the mudline to be warmed by the hot circulating drill mud coming up the annulus from the bottom for some distance away from the wellhead. After the well is cased, it will take some time for the upper part of the well to once again cool down to its normal state, which will be cold. When this happens, the casing strings in the upper uncemented part of the well could see very dramatic cooling effects that will change casing loads to levels possibly exceeding connection capacity. Circulating fluid temperatures in the riser can also influence the shape of the circulating temperature curve and the crossover depths between cooling and heating of the wellbore, which can impact casing installation operations. A riser with flotation modules vs one without will also impact temperature effects on the circulating fluid system during the placement of tubulars and also need to be taken into account. Figure 2A-5 shows an example of how a deepwater temperature profile changes from long-term circulation during the drilling process and after the well is left shut-in over a long period of time. These changes and others as the well is produced, stimulated or shut-in for long periods of time must be taken into consideration in designing the casing strings in the upper part of the well which is left uncemented but fixed on both ends. (Several service companies have computer programs available to run simulations for many of these variables that can influence the temperature behavior of a circulating system and the surroundings so that they can be used to plan the design of a safe and effective completion over the life of the well.)

Chapter 3
Hydraulics

TABLE OF CONTENTS

3.1 INTRODUCTION

This chapter describes a proven technique which maximizes either the hydraulic impact force or the hydraulic power of drilling fluid striking the bottom of a borehole. The procedure has also been incorporated into API Recommended Practice 13D — Rheology and hydraulics of oilwell drilling fluids.

This chapter presents a method of removing as many cuttings as possible from beneath the drill bit with the hydraulics available on any particular drilling rig. To facilitate application of the process for the second and subsequent times, the procedure is outlined below. This synopsis is designed to make it easier to apply this technology after understanding the explanations which follow. After listing the eleven steps, the process will be developed and a discussion of each procedural step is presented in this chapter. Technical discussions and some equation derivations are presented in the appendix to this chapter.

Below are stepwise instructions to maximize hydraulic power and hydraulic impact:

1. Calibrate rig pumps. Measure the rate of liquid level drop in the slug tank while pumping down hole through the drill bit. Account for air in the drilling fluid to calculate the volume of liquid being pumped;
2. 2. Draw the maximum pressure limit and the available power curves on log-log graph paper. This defines the available flow rates and pressures available for that specific drilling rig;
3. Just before tripping for a new bit, circulate at several pump rates and accurately measure the standpipe pressure at each rate. The pump rates should be mostly near the normal operating range used while drilling. Do not use slow pump stroke rates;
4. Calculate and subtract the bit nozzle pressure drops from the measured standpipe pressures. (This gives the circulating pressure loss through the system, except for the bit nozzles.);
5. Plot the circulating pressure loss as a function of flow rates on log-log paper;
6. Draw the best straight line through the circulating pressure losses;
7. Measure the slope of the circulating pressure line with a ruler or scale. Preferably, use two data points on the line and calculate the slope "μ";
8. Calculate the optimum pressure loss through the bit to give either the maximum hydraulic force or the maximum hydraulic power at the bit;
9. Subtract the optimum pressure losses from the maximum pressure and draw the "optimum circulating pressure" line;
10. The optimum flow rate is the flow rate where the circulating pressure loss (Pcirc) intersects the optimum pressure line;
11. Using the optimum flow rate and the optimum bit nozzle pressure loss, calculate nozzle sizes for the next bit.

3.2 Detailed discussion of procedure

The objective of this process is to determine the best flow rate and pressure drop through bit nozzles to cause the fluid to strike the bottom of the hole with the most force possible or to expend the most power through the bit nozzles. The step-by-step procedure was presented above in an abbreviated form. Each step needs to have some technical discussion. These discussions follow and the technical derivations are presented in the Appendix of this chapter.

3.2.1 Background

Drilling fluid has many functions. One important function is to remove cuttings from beneath a drill bit before the next row of cutters contact the cuttings. If cuttings are broken by a second group of cutters, the cuttings become significantly smaller and more difficult to remove. The energy used by the bit to regrind cuttings also tends to decrease drilling rate. If many cuttings remain on the bottom of the hole, bit teeth may cease to contact new formation and drilling rates become very low. This could be mistakenly viewed by drillers as "hard rock" when actually the rock is not hard. In many cases, the drill bit is "balled-up" — meaning that cuttings have adhered to the cutting structure and the bit.

Hydraulic optimization can mean many things to many different drilling personnel. It can refer to maximizing annular flow rate, maximizing the standpipe pressure, maximizing the flow rate through the bit nozzles, maximizing the force with which the fluid strikes the bottom of the hole (impact), or maximizing the power expended through the nozzles in the drill bit (hydraulic power). Increasing flow rate is frequently incorrectly used to improve bottomhole cleaning. Too much of the applied surface pressure is lost within the pressure loss inside of the drill string which leaves too little pressure for the bit nozzles. The development in this chapter focuses on a method to maximize cuttings removal beneath a drill bit. Better cuttings removal results in elevated bit founder points and promotes faster drilling.

3.2.2 Rig flow systems

Positive displacement mud pumps circulate drilling fluid down the drillpipe and back up the annulus. Each rig has a primary mover, or motors, which power the pumps. These motors have a maximum power output. The hydraulic power (HHP) obtained from the mud pumps is calculated from the available input power (HP) and the efficiency of power transfer (Em) and volumetric efficiency (E_V):

$$HHP = Em\,(E_V)(HP) \qquad \textbf{Equation 3-1}$$

The volumetric efficiency can be measured by measuring

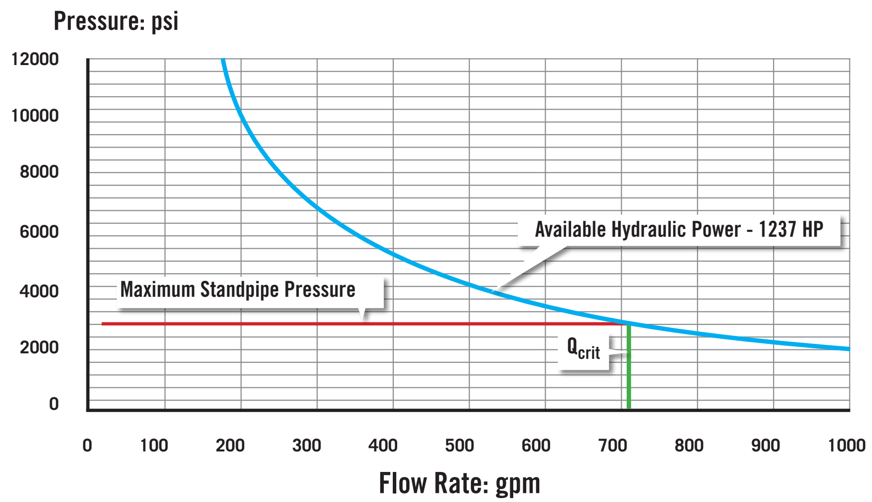


Figure 3-1: Hydraulic limit conditions on drilling rig.

the volume leaving a small slug tank and comparing it with the pump piston displacement during that period of time. This test can be performed while drilling. Usually, however, since this data is seldom available, a value of 97% is used for the volumetric efficiency. This value will decrease significantly if air or gas is in the drilling fluid.

The mechanical power transfer from the motors to the pumps is usually considered to be about 85%. Without actual measurements, the hydraulic power available from the mud pumps is therefore :

HHP = (0.97)(0.85)(1,500HD) = 1,237 hp **Equation 3-2**

Each drilling rig will have a maximum pressure limit available for the fluid pumped to the standpipe. This limit may be the pressure rating of a mud pump liner, a value in a contract, a practical value because of some rig limitation, or for some other reason. At some flow rate, the maximum pressure can no longer be achieved because of the hydraulic power available. When this point is reached, the flow rate is called "the critical flow rate" or Q_{crit}. Above the critical flow rate the surface pressure decreases as the flow rate increases. This provides the 'hydraulic playing field' available for pressure and flow rate. In the illustration below, the maximum pressure available is 3,000 psi and the motors driving the mud pumps are 1,500 hp.

The available hydraulic power is 82.5% of the 1,500 hp created by the motors. The maximum standpipe pressure is 3,000 psi. At a flow rate of 900 gpm , the maximum pressure would be limited to 2,356 psi because insufficient power is available to move 900 gpm at a pressure of 3,000 psi (Figure 3-1).

At a flow rate of 707 gpm, the rig would be using all of the power available at the maximum possible pump pressure, indicating that 707 gpm is Q_{crit}. Q_{crit} is calculated from Equation 3-3, which relates hydraulic horsepower to pressure and flow rate:

HHP = [P Q]/1,714 **Equation 3-3**

Where:

HHP is the hydraulic horsepower, hp
P is the pressure, psi
Q is the flow rate, gpm

Solving Equation 3.3 for Q, and substituting known values of hydraulic horsepower and pressure into the equation to determine Q_{crit}:

Q_{crit} = 1,714 HHP/P = 1,714 (1,237 hp) / 3,000 psi
= 706 gpm **Equation 3-4**

Independent of whether the pressure is limited by the maximum pressure available at the rig or whether the pressure is limited by the hydraulic power, there is always a maximum pressure available for pumping drilling fluid down the drill string.

This maximum pressure is divided into two parts: the pressure loss through the drill bit and the pressure loss through the drill string. Obviously, a lower pressure loss through the drill string will provide more pressure through the bit. Calculating the pressure loss through the drill string is a very complicated problem. In laminar flow, pressure drop through a pipe varies with the inside diameter, the length of the pipe, the viscosity of the fluid, and the flow rate. In turbulent flow, the pressure drop through a pipe varies with the inside diameter, the pipe length, the square of the velocity, and the 0.2 power of the viscosity. In most drilling operations, the drilling fluid is a non-Newtonian fluid and the viscosity varies with flow rate as well as temperature. Pressure losses in a drill string are discussed in depth in Appendix 3A.

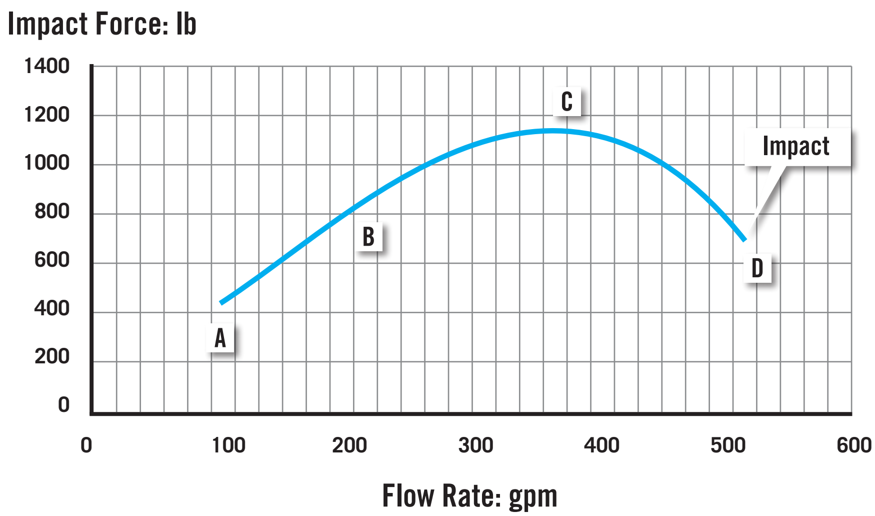


Figure 3-2: Impact force of fluid exiting from a nozzle is a function of the flow rate.

3.3 Calculating the maximum hydraulic impact force at the bit

Hydraulic impact force is calculated from the product of the density, flow rate, and the nozzle velocity. When only a small flow rate is pumped down the drill string, the pressure loss in the drill string is very low which leaves a large pressure available for the drill bit nozzles. The velocity of drilling fluid flowing through the nozzles is directly related to the pressure loss through the bit. If the flow rate is low and the nozzle velocity is high, the product may be a low value. As the flow rate is increased, the pressure loss in the drill string increases, which decreases the nozzle velocity. The product of the flow rate and the nozzle velocity will increase. This increase in hydraulic impact (density times flow rate times nozzle velocity) will reach a maximum value which depends greatly on the pressure loss within the drill string. Further increases in flow rate will increase the pressure loss in the drillpipe leaving a much lower pressure available for the drill bit nozzles. A lower pressure loss across the bit nozzles will decrease the nozzle velocity. The hydraulic impact will decrease as the nozzle velocity decreases more rapidly than the flow rate increases. The curve resembles a parabola, as shown in Figure 3-2. This curve may be described mathematically and the maximum point defined by the tangent to the curve, as explained in Appendix 3B.

At Point A in Figure 3-2, the flow rate is very low, which means the pressure loss in the drill string and annulus will be very low. This leaves a very large pressure available to apply across the drill bit nozzles. A very large pressure drop will produce a large velocity of the fluid passing through the nozzles. Hydraulic impact is the product of density (or mud weight), flow rate, and fluid velocity. Even though the nozzle velocity will be very large, the low flow rate will produce a low hydraulic impact. As the flow rate is increased, the pressure loss in the drill string and annulus will increase. This leaves less pressure to apply across the bit nozzles. The product of the flow rate and the nozzle fluid velocity increases. At Point C, the impact force is a maximum value. This flow rate which produces this maximum can be determined mathematically. The mathematical derivation for this maximum value is presented in Appendix 3A. As the flow rate is increased to a larger value, the pressure loss in the drill string and annulus becomes larger and the pressure remaining for the bit nozzles is decreased significantly. This means that the nozzle velocity will be much lower. The mathematical product of the nozzle velocity and flow rate will be lower, meaning the hydraulic impact will be lower.

As an additional point notice that the curve is not symmetric about Point C. At a low flow rate, much of the flow in the drillpipe will be laminar; at the higher flow rates, much of the flow will be turbulent. Pressure losses for these two regimes are much different for the same drilling fluid. This is discussed in detail in Appendix 3B.

The maximum value of impact force is a function of the pressure loss within the drill string. The curve could also be developed by running the drill string in the hole without the drill bit and pumping at a variety of different flow rates. This is obviously impractical. The standpipe pressure measures the total pressure loss in the drill string and the drill bit. Since the nozzle pressure losses can be calculated with reasonable accuracy, the drill string and annulus pressure loss for any circulation rate can be determined by subtracting the nozzle pressure loss from the standpipe pressure. For convenience, this pressure loss is called P_{circ}. Mathematically:

$$P_{circ} = P_{standpipe} - P_{bit} \qquad \textbf{Equation 3-5}$$

P_{circ} is proportional to some power of the flow rate.

$P_{circ} = K(Q^{\mu})$ **Equation 3-6**

Where K is a constant of proportionality, Q is the flow rate, and "μ" is the exponent.

If the flow in the pipe is laminar, the exponent "μ" will be one. If the flow in the pipe is turbulent, the exponent will be close to two. Generally in a drillpipe, each tool joint initiates turbulence.

If the drilling fluid is very viscous, the turbulent zone will be very short and most of the flow could be laminar, image A in Figure 3-3. The distance that flow remains turbulent depends upon the fluid properties. For example, if the fluid is water or the fluid has a low viscosity in this shear rate range, the turbulent flow will persist for a significant distance down the drillpipe below the tool joint, image C in Figure 3-3. The ratio between the laminar and turbulent pressure losses cannot be predicted ahead of time. The exponent "μ" can be determined on a drilling rig as discussed in Appendix A at the end of this chapter. Many computer programs use an exponent of 1.8 as a "generic" value.

3.4 Calculating the maximum hydraulic power at the bit

Hydraulic power is the product of the density, flow rate, and square of the nozzle velocity. When the drilling fluid flow rate is low, very little pressure losses in the system leave a very large pressure available for the nozzles. The velocity of the drilling fluid through the nozzles is directly related to the pressure across the nozzles. As the flow rate is increased, less pressure is available across the nozzles because of the pressure losses inside of the drill string increases. At some flow rate, the hydraulic power reaches a maximum value. At

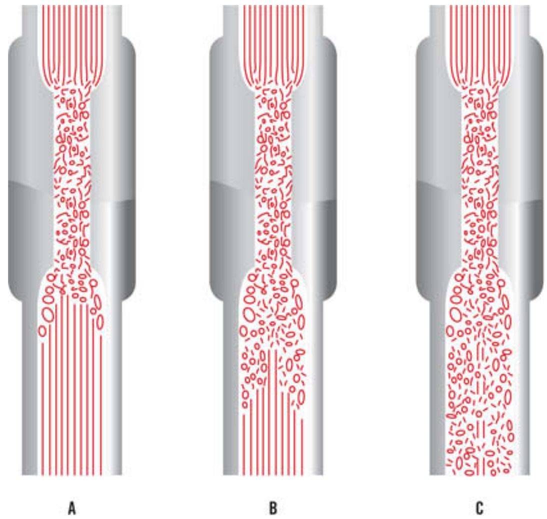


Figure 3-3: Tool joints interrupt the flow profile of the fluid.

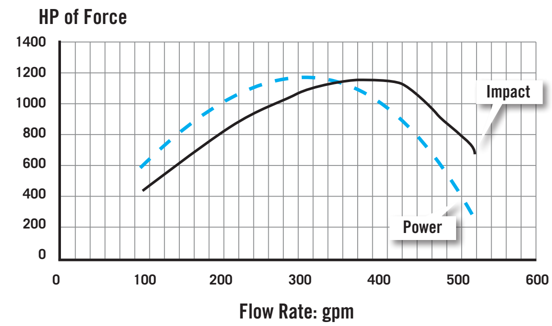


Figure 3-4: Comparing maximum impact with maximum power.

a little higher flow, the hydraulic impact reaches a maximum value. As the flow rate is increased some more, these optimum flow rate values can be determined from the pressure losses in the circulating system omitting the pressure loss through the bit nozzles. A discussion of these pressure losses is presented in Appendix 3B.

The maximum values for both parameters extend over a reasonable range of flow rates, Figure 3-4. That is, the peak values are not very narrow regions on the chart. As the flow rate continues to increase, the pressure available for the nozzles decreases significantly. When the flow rate is very large, very little pressure is available for the nozzles. Both the hydraulic impact and hydraulic power available for the bit decrease rapidly after reaching the maximum as the flow rate increases. The mathematical development, presented in the Appendix 3B at the end of this chapter, simplifies the measurements needed on a drilling rig to locate these maximum values.

The tendency on a drilling rig is to try to increase the fluid power through the drill bit by increasing the flow rate down the drillpipe. The fallacy of this effort is clear from the graph in Figure 3-4. At a very high flow rate, a very high pressure loss occurs within the drillpipe. Very little pressure is left for the drill bit.

3.5 Calculating the optimum flow rate

To determine the flow rate which will produce the maximum hydraulic impact or the maximum hydraulic power of the fluid passing through the bit nozzles, the equations representing the curves shown in Figure 3-4 are differentiated to obtain the maximum values. The resulting equations relate to the exponent "μ", presented in the Equation 3-7, calculating the pressure loss as a function of flow rate.

$P_{circ} = K(Q^{\mu})$ **Equation 3-7**

3.6 Achieving maximum hydraulic power

For maximum hydraulic power, the limiting feature on a drilling rig will always be the maximum standpipe pressure possible. The optimum pressure loss through the drill bit will be:

$$\Delta P_{\substack{bit\\opt}} = \frac{\mu}{\mu+1} P_{max} \qquad \textbf{Equation 3-8}$$

This will normally result in a lower flow rate in the well than optimizing for hydraulic impact.

3.7 Achieving maximum hydraulic impact force

The optimization procedure for maximum impact force of the drilling fluid striking the bottom of the hole depends upon what is limiting the maximum pressure available. If the flow rate needed is higher than Q_{crit}, the limiting condition will be hydraulic power. If the flow rate needed is less than Q_{crit}, the limiting condition will be the maximum pressure available.

3.7.1 Power limited

If the limiting condition is hydraulic power, the pressure loss through the bit which creates the maximum impact force obtained from the fluid flowing through the bit nozzles, can be calculated from the equation:

$$\Delta P_{\substack{bit\\opt}} = \frac{\mu+1}{\mu+2} P_{HP} \qquad \textbf{Equation 3-9}$$

3.7.2 Pressure limited

If the limiting condition is standpipe pressure, the pressure loss through the bit which creates the maximum impact force, obtained from the fluid flowing through the bit nozzles, can be calculated from the equation:

$$\Delta P_{\substack{bit\\opt}} = \frac{\mu}{\mu+2} P_{max} \qquad \textbf{Equation 3-10}$$

3.8 Procedure

The objective of this process is to determine the best flow rate and pressure drop through bit nozzles to cause the fluid to strike the bottom of the hole with the most force possible or to expend the most power through the bit. The step-by-step procedure is presented below. Each step needs to have some technical discussion. These discussions follow and the technical derivations are presented in Appendix 3A of this Chapter.

1. Calibrate rig pumps. Measure the rate of liquid level drop in the slug tank while pumping downhole through the drill bit. Account for air in the drilling fluid to calculate the volume of liquid being pumped;
2. Draw the maximum pressure limit and the available power curves on log-log graph paper. This defines the available flow rates and pressures available for that specific drilling rig;
3. Just before tripping for a new bit, circulate at several pump rates and accurately measure the standpipe pressure at each rate. The pump rates should be mostly near the normal operating range used while drilling;
4. Calculate and subtract the bit nozzle pressure drops from the measured standpipe pressures. (This gives the circulating pressure loss through the system, except for the bit nozzles.);
5. Plot the circulating pressure loss as a function of flow rates on log-log paper;
6. Draw the best straight line through the circulating pressure losses;
7. Calculate the value of "μ" from Equation 3-7 using two data points on the line or measure the slope of the circulating pressure line with a ruler or scale. (To use a ruler for measuring the slope, the graph must be square.);
8. The optimum pressure loss through the bit to give either the maximum hydraulic force or the maximum hydraulic power at the bit;
9. Subtract the optimum pressure losses from the maximum pressure and draw the "optimum pressure" lines;
10. The optimum flow rate is the flow rate where the circulating pressure loss (Pcirc) intersects the optimum pressure line;
11. Using the optimum flow rate and the optimum bit nozzle pressure loss, calculate nozzle sizes for the next bit.

These instructions will be explained more completely in the section below.

3.9 Detailed discussions of procedure

3.9.1 Comment step 1: calibrate mud pumps

Drilling rigs usually have positive displacement mud pumps. Large motors drive the pumps and usually the horsepower rating of these prime movers is known. Not all of the power can be transmitted to the pumps. The power available to pump drilling fluid is may be calculated by multiplying the available power by a mechanical energy transfer efficiency and the volumetric efficiency. Usually, the mechanical energy transfer is about 85% of the available power. The volumetric efficiency varies with the manner in which the pump liners are filled and the amount of gas (air, methane, or whatever) in the drilling fluid. The pump volumetric efficiency may be measured while drilling by taking suction from a slug tank. If this step is not possible, assume that the pump volumetric efficiency is 97%. Volumetric efficiencies as low as 85% have been observed in the field. The calibration procedure is presented in Appendix 3C.

3.9.2 Comment step 2

Draw pressure limits for maximum standpipe values at the lower flow rates and the maximum pressure available when

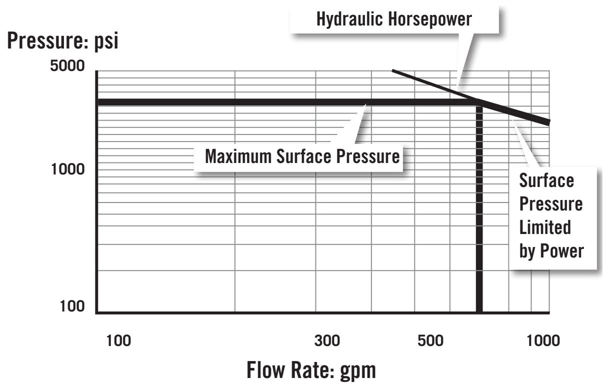


Figure 3-5: Hydraulic limit conditions.

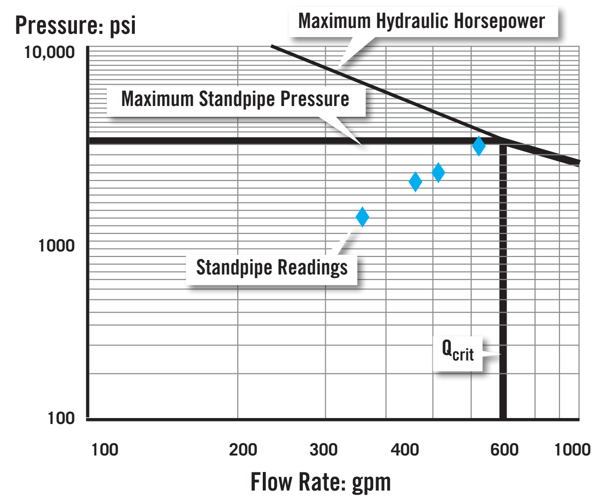


Figure 3-6: Standpipe pressures plotted on hydraulic limit conditions.

power is limiting. These limits are usually drawn on log-log paper so that the exponent "μ" can be measured easily with a ruler. Essentially this straightens the lines from curves on a linear plot (like the line shown in Figure 3-1) to straight lines on a log-log plot.

Caution should be observed for log-log graphs drawn by many computer programs, such as the one in Figure 3-5. The ordinate and abscissa should have the same physical linear dimension before measuring the slope with a rule (making a square graph). This means that the distance between 100 and 1,000 should be the same as the distance between 1,000 and 10,000 on the x-axis. The distance between 100 and 1,000 should be the same as the distance between 1,000 and 10,000 on the y-axis. The distance between 100 and 1,000 should be the same on the x and y axis. A line connecting the (x, y) coordinates of (100, 100) and (1000, 1000) should be 45^{o} from the x-axis.

3.9.3 Comment step 3

Measure standpipe pressure for at least four different pump stroke rates while pumping bottoms-up. Use stroke rates close to the operating values. When the flow rate decreases significantly, some of the turbulent flow becomes laminar and that changes the slope of the curve.

3.9.4 Comment step 4

Calculate the bit nozzle pressure drops for each of the measured standpipe pressures. The equation is derived in Appendix 3E.

$$P = \frac{(MW)\,(Q^2)}{12{,}032\,(1.03)^2\,(A^2)} \qquad \textbf{Equation 3-11}$$

3.9.5 Comment step 5

The standpipe pressure is the sum of the pressure drop through the drill bit nozzles and the rest of the circulating system. The pressure loss through the circulating system (P_{circ}) could be considered wasted energy. The circulating pressure loss (P_{circ}) may be calculated by subtracting the bit pressure loss from the standpipe pressure at that flow rate.

3.9.6 Comment step 6

Drawing the "best" straight line through the data points may be difficult. Fraction of fluid in turbulent flow will decrease as the flow rate decreases. Data should be acquired using pump strokes close to the normal flow rates used while drilling. The slope of the line will become almost a value of one if the flow rate is very low. Generally, the slow pump stroke rate used for pumping out kicks will not be satisfactory for data acquisition. The upper range of values should be given a higher priority for construction of the P_{circ} line.

The computer-generated graph in Figure 3-7 does not have the same linear distance per decade of numbers (in other words, the graph is not square). Re-plotting this information on the correct graph paper dimensions, Figure 3-8, indicates that the slope is seven inches divided by five inches or 1.4. Instead of re-plotting, two points on the graph could be used to mathematically solve for the proportionality constant (K) and the slope (μ) using Equation 3-6, as shown.

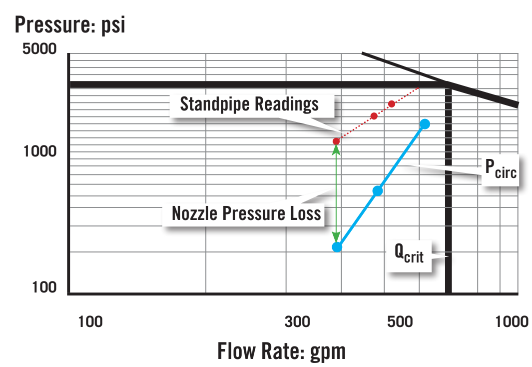


Figure 3-7: Plotting the circulation pressure losses through the drillpipe and annulus.

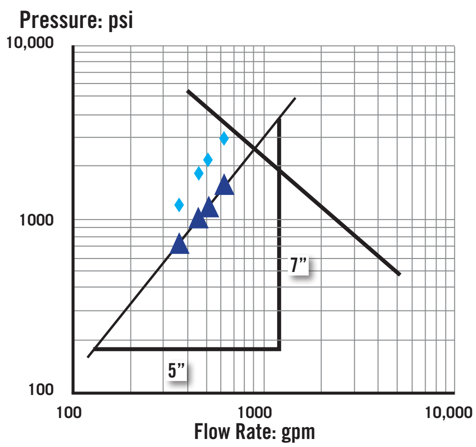


Figure 3-8: Circulating pressure losses plotted on correct graph paper to measure slope of line.

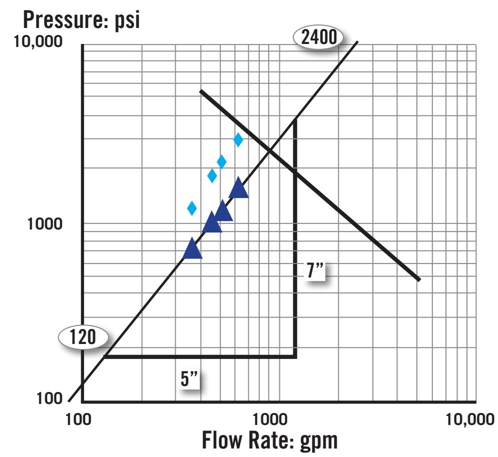


Figure 3-9: Extend the lines in Figure 3.8 to calculate the values of “u”.

The best procedure would be to calculate the value of the slope “μ” by using two points on the curve in Figure 3-7. Select two points on the curve [not from the data]. Write two equations and insert the values of the flow rate and the pressure into each equation. Solve these two equations for the value of “K” and the value of “μ”.

$P_{circ} = K\,Q^{\mu}$ **Equation 3-12**

$\log P_{circ} = \log K + \mu \log Q$ **Equation 3-13**

$\log 200 = \log K + \mu \log 140$ **Equation 3-14**

$\log 10{,}000 = \log K + \mu \log 2{,}400$ **Equation 3-15**

$\log 10{,}000 - \log 200 = \mu (\log 2{,}400 - \log 140)$ **Equation 3-16**

$4.0 - 2.3 = \mu\,[3.38 - 2.15]$ **Equation 3-17**

$\mu = 1.4$ **Equation 3-18**

Calculate “K”

$P_{circ} = K\,(Q^{\mu})$ **Equation 3-19**

$200 = K\,(140^{1.4})$ **Equation 3-20**

$K = 200/1011 = 0.198$ **Equation 3-21**

The equation for P_{circ} is:

$P_{(circ)} = 0.198\,Q^{1.4}$ **Equation 3-22**

3.9.7 Comment step 8

At this point the decision must be made about whether to use the flow rate to give the maximum hydraulic force or the maximum hydraulic power at the bit. The correct pressure loss through the bit nozzles calculated:

Maximum hydraulic power

$$\Delta P_{\substack{bit\\opt}} = \frac{\mu}{\mu+1} P_{max}$$ **Equation 3-23**

Maximum force: power limited

$$\Delta P_{\substack{bit\\opt}} = \frac{\mu+1}{\mu+2} P_{max}$$ **Equation 3-24**

Maximum force: pressure limited

$$\Delta P_{\substack{bit\\opt}} = \frac{\mu}{u+2} P_{max}$$ **Equation 3-25**

For this example, the maximum hydraulic impact will be chosen for the optimization procedure. An example of choosing the maximum hydraulic power will be discussed after this comment section is completed.

The optimum pressure loss through the drill bit nozzles for maximum hydraulic impact force is subtracted from the limiting pressure. In the case of the illustration in Step 6, the pressure loss would be:

$$\Delta P_{\substack{bit\\opt}} = \frac{1.4}{1.4 + 2}\ 3{,}000 \text{ psi} = 1{,}235 \text{ psi}$$ **Equation 3-26**

Subtract 1,235 psi from the limiting pressure (3,000 psi) and draw a line for the optimum pressure loss in the circulating system at a pressure of 1,765 psi.

3.9.8 Comment step 10

The line drawn at a pressure of 1,765 psi shows the pressure loss in the circulating system which would still leave the necessary 1,235 psi pressure for the drilling fluid to strike the bottom of the hole with the most force. Pumping about 620 gpm down the drillpipe will create a pressure loss in the entire circulating system of 1,765 psi (which leaves 1,235 psi available for the drill bit nozzles).

3.9.9 Comment step 11

With the pressure loss through the nozzles known (P = 1,235 psi), the flow rate known (Q = 620 gpm), and the mud weight (MW) known, the nozzle area can be calculated from the equation:

$$P = \frac{(MW)\,(Q^2)}{12{,}032\,(1.03)^2\,(A^2)} \qquad \textbf{Equation 3-27}$$

Tables are provided in Appendix 3D to convert nozzle areas into common nozzle sizes.

3.10 Maximum hydraulic power at the bit

For hydraulic power, the optimum pressure loss through the drill bit nozzles would be calculated from the equation:

$$\Delta P_{\substack{bit\\opt}} = \frac{\mu}{\mu+1} P_{max} \qquad \textbf{Equation 3-28}$$

or

$$\Delta P_{\substack{bit\\opt}} = \frac{1.4}{1.4+2} 3{,}000 \text{ psi} = 1{,}235 \text{ psi} \qquad \textbf{Equation 3-29}$$

If the optimum pressure loss through the drill bit nozzles is 1,750 psi and the maximum pressure is 3,000 psi, the optimum circulating pressure loss would be 3,000 psi – 1,750 psi or 1,250 psi. Draw this horizontal line on the pressure-flow rate chart. The proper flow rate to produce this optimum circulating pressure loss will be where that line intersects the circulating pressure line.

3.10.1 Circulating pressure line

The equation for the circulating pressure line would indicate that the circulating pressure is equal to a constant times the flow rate raised to the 1.4 power. The constant can be determined from one of the data points (P = 739 psi; Q = 361 gpm or K = 0.194). The optimum circulating rate can now be calculated from the equation:

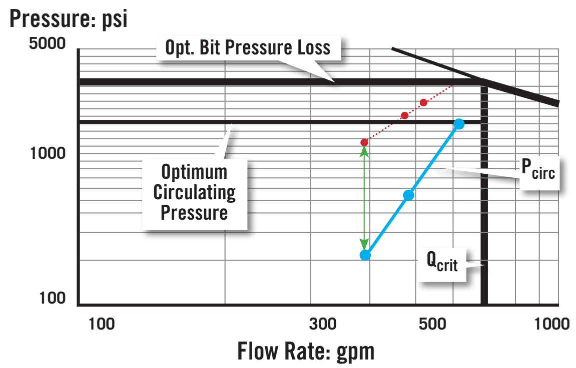


Figure 3-10: Optimum circulating pressure line.

$$1{,}250 \text{ psi} = (0.194)(Q^{1.4})_{opt} \qquad \textbf{Equation 3-30}$$

or

$$Q_{opt} = 526 \text{ gpm} \qquad \textbf{Equation 3-31}$$

In this case the optimum flow rate from the graph would be 526 gpm and the pressure loss through the bit nozzles should be 1,250 psi. Using this flow rate and bit pressure loss will cause the drilling fluid to expend the maximum possible hydraulic power at the bottom of the hole. From the equation for pressure loss through the drill bits, the nozzle area may be calculated and proper nozzles dressed into the new drill bit, Equation 3-32:

$$\text{Area} = \frac{(11.7 \text{ ppg})\,(525 \text{ gpm})^2}{12{,}042\,(1.03)^2\,(1{,}250 \text{ psi})} = 0.2019 \text{ in.}^2 \qquad \textbf{Equation 3-32}$$

The bit can be dressed with one 11⁄32-in. and one 12⁄32-in. nozzles or one 9⁄32-in. and two 10⁄32-in. nozzles.

3.11 Maximum impact force

The P_{circ} line crosses the optimum line in a region where the flow rate will require a lower standpipe pressure to prevent exceeding the horsepower available on this rig.

3.11.1 Power limited

$$\Delta P_{\substack{bit\\opt}} = \frac{\mu+1}{\mu+2} P_{max} \qquad \textbf{Equation 3-33}$$

$$\Delta P_{\substack{bit\\opt}} = \frac{2.4}{3.4} P_{max} = (0.71)\,(3{,}000 \text{ psi}) = 2{,}130 \text{ psi} \qquad \textbf{Equation 3-25}$$

3.11.2 Limited

If the limiting condition is standpipe pressure, the pressure loss through the bit which creates the maximum impact force, obtained from the fluid flowing through the bit nozzles, can be calculated from the equation:

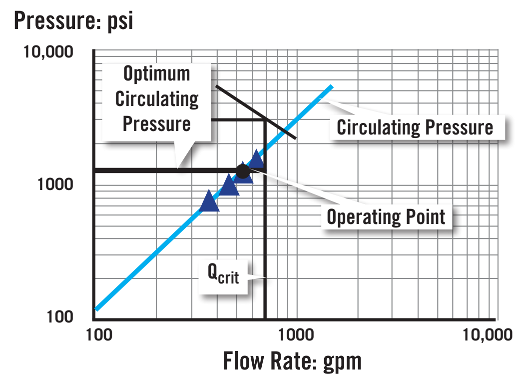


Figure 3-11: Illustrating selection of operating pressure and flow rate to achieve the maximum hydraulic impact of the drilling fluid through the nozzles.

$$\Delta P_{\substack{bit\\opt}} = \frac{\mu}{\mu+2} P_{max} \qquad \textbf{Equation 3-35}$$

$$\Delta P_{\substack{bit\\opt}} = \frac{1.4}{3.4} P_{max} = (0.41)\ (3{,}000\ \text{psi}) = 1{,}235\ \text{psi} \qquad \textbf{Equation 3-36}$$

3.12 Illustration of the graphical solutions for maximum hydraulic force and maximum hydraulic power

In all of the illustrations below, the standpipe pressure was measured for several different flow rates. These are not plotted. The pressure loss through the nozzles was calculated and subtracted from the standpipe pressure at each flow rate. The resulting pressure losses are called P_{circ} and are plotted on each chart. Three limits are discussed in the illustration examples presented below. The upper part of the hole normally has a hydraulic power limit; the next section of a wellbore has a limit of both the hydraulic power and the maximum standpipe pressure; the lower part of a hole normally has a standpipe pressure limit when all of the available horsepower cannot be used. Each of these conditions will be illustrated below.

3.12.1 Upper part of a borehole

Maximum Hydraulic Impact
For a Power Limited Case

In the upper part of a well, pressure losses inside the drillpipe and up the annulus are very low. In the graph below, most of the flow is laminar, probably because of the very viscous drilling fluid used to clean the large diameter borehole. The slope of the P_{circ} vs Q curve is 1.3. This value of the slope is used to find the optimum pressure loss through the nozzles from the equations derived in Appendix 3B . The P_{circ} line crosses the optimum pressure line at a flow rate of 820 gpm and is in the region where available hydraulic power limits the maximum pressure that can be used. In this case the maximum pressure available would be 2,590 psi not the 3,000 psi maximum available on the drilling rig. At this pressure and flow rate, 860 hydraulic horsepower (HHP) would be available at the bit from the 1,237 hhp available from the pumps. The difference between 1,237 hhp and 860 hhp (or 377 hhp) would be lost in the drill string and the annulus.

Frequently, when drilling large-diameter holes in the upper part of a well, two pumps are placed in parallel to provide more hydraulic power so the standpipe pressure can be the maximum value. The limit conditions would double the available hydraulic power and could be plotted in the same manner as the chart below. Two pumps in parallel would have the 3,000 psi maximum pressure limit but could probably provide the maximum pressure of 3,000 psi.

3.12.2 Intermediate part of a borehole

As a borehole gets deeper, more drillpipe is added and the pressure loss through the drill string and up the annulus increases. This means that the P_{circ} line moves up to a higher pressure value for any flow rate. Usually, the slope increases. In this example, the slope (or value of μ) increased to a value of 1.5. In this case, the P_{circ} crosses the Q line at a pressure reading of 857 psi. The pressure loss through the nozzles should be (3,000 psi – 857 psi) or 2,143 psi. This pressure loss at a flow rate of 706 gpm will cause the drilling fluid to strike the bottom of the hole with the most force possible with this drilling fluid system. Using these parameters, the correct nozzle size may be selected for the next drill bit.

3.12.3 Lower part of a borehole

As the well gets deeper, more pressure is lost inside the drill string and annulus. Usually, the slope of the P_{circ} line (or μ) increases, possibly because of more and more tool joints in the drill string and changes in the drilling fluid properties. In the chart below, the value of "μ" was determined to be 1.6. The P_{circ} line crosses the optimum pressure line at 1,330 psi and a flow rate of 480 gpm. The pressure loss through the bit of (3,000 psi – 1,330 psi) or 1,670 psi at a flow rate of 480 gpm will cause the fluid to strike the bottom of the hole with the most force possible with this drilling fluid system. The nozzle areas may be calculated from these parameters as illustrated in previous section.

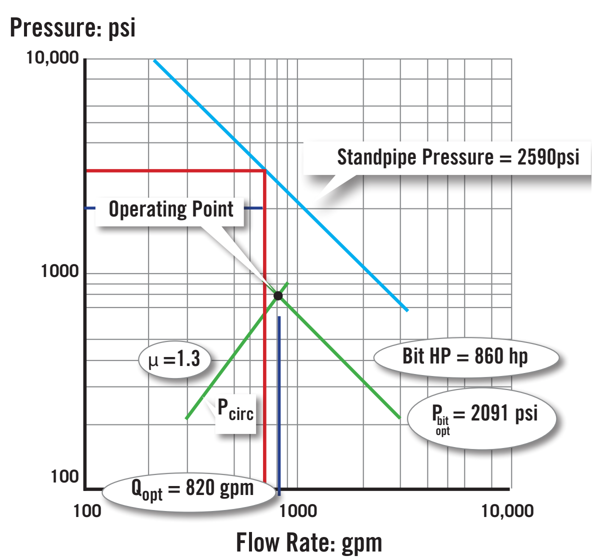


Figure 3-12: Maximum hydraulic impact where the standpipe pressure is limited by the available hydraulic power.

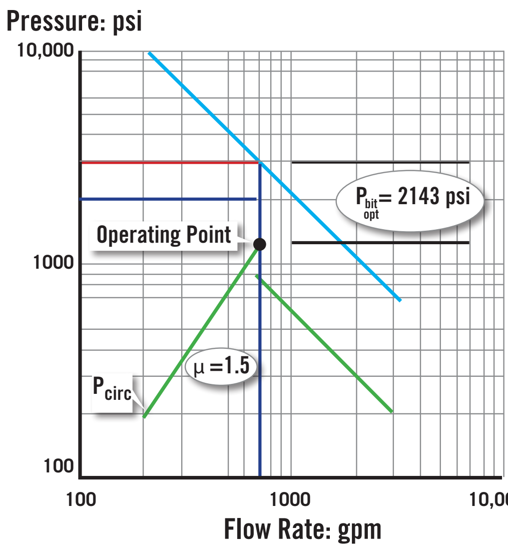


Figure 3-13: Maximum hydraulic impact of fluid from nozzles where all of the available hydraulic power can be used with the maximum standpipe pressure.

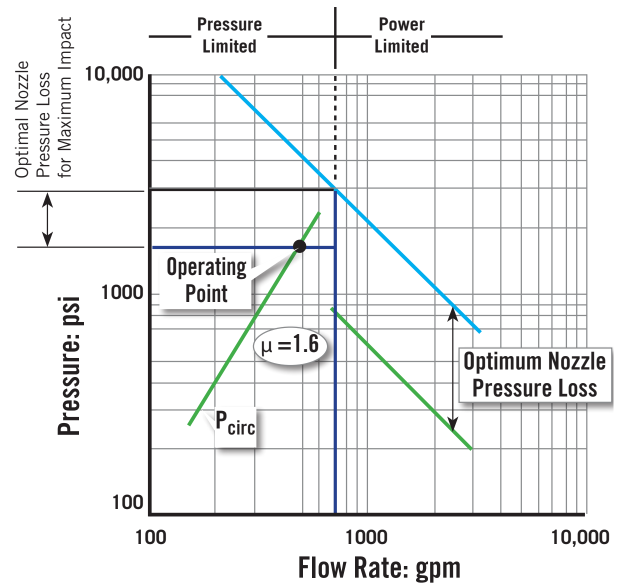


Figure 3-14: Drilling fluid hits the bottom of the borehole with the maximum force possible where the standpipe pressure is the limiting condition.

3.13 Maximum hydraulic power at the nozzles

Currently, common practice seems to be to maximize the hydraulic power at the bit nozzles when drilling with polycrystalline diamond compact (PDC) bits. This is usually reported in HSI or hydraulic power per square inch of borehole area. This practice probably has developed because of the cutting mechanism of PDC bits although validation of this criteria does not seem to be published in the literature.

In Figure 3-15, the data from the three different depths (resulting in the values of "μ" increasing from 1.3 to 1.5 to 1.6) are shown on the graph created for obtaining the maximum hydraulic power through the bit nozzles.

The optimum conditions require that the maximum available power (1,237 hp) with the maximum standpipe pressure be used as long as possible. The Q_{crit} flow rate (706 gpm) becomes the optimum flow rate until the well becomes so deep that all of the available mud pump power can no longer be used. The standpipe pressure will always be the maximum value of 3,000 psi for all situations.

The proper nozzle pressure loss for μ=1.3 will be 2,345 psi at a flow rate of 706 gpm. This will provide a hydraulic power of 966 hp at the drill bit and will be the largest possible power.

As an exercise using the μ=1.3 curve, calculate the power generated if a 300-gpm flow is used instead of the optimum value of 706 gpm. The pressure loss in the circulating system was measured to be 215 psi (see graph). The maximum standpipe pressure would be 3,000 psi; leaving 2,785 psi available for the bit. This results in a hydraulic power of (2,785 psi)(300 gpm)/1,714 or 350 hp. This illustrates the effect of trying to achieve the maximum pressure loss across nozzle which results in a lower hydraulic power at the bit.

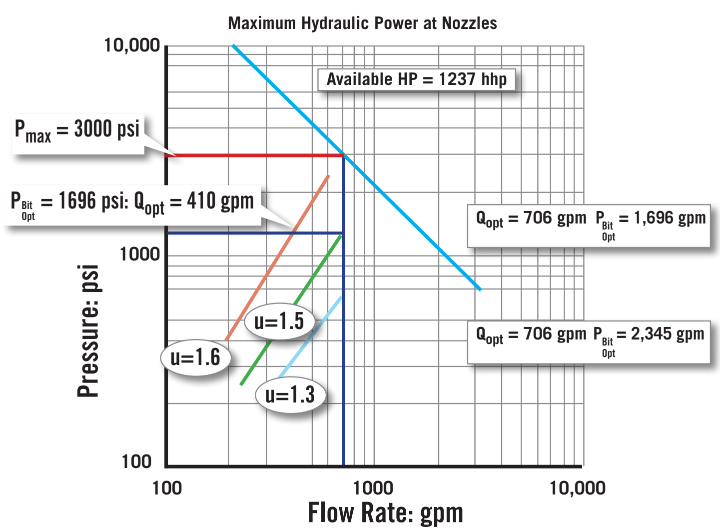


Figure 3-15: Developing the maximum possible hydraulic power of the drilling fluid flowing through the bit nozzles at three different depths.

3.14 Example problem

While drilling with an 11.0 ppg drilling fluid with an IADC 537 drill bit, the three nozzles were dressed with two 16⁄32-in. and one 18⁄32-in. diameter nozzles. The rig has 1,700 hp available for the mud pumps which have a maximum pressure limit of 4,000 psi. The large nozzles are installed so that the annular velocity can bring cuttings out of the hole and the improve the hydraulic power at the drill bit. Just before pulling the dull bit, the driller pumped bottoms-up with six different pump stroke rates and measured the standpipe pressures.

3.14.1 Limit conditions

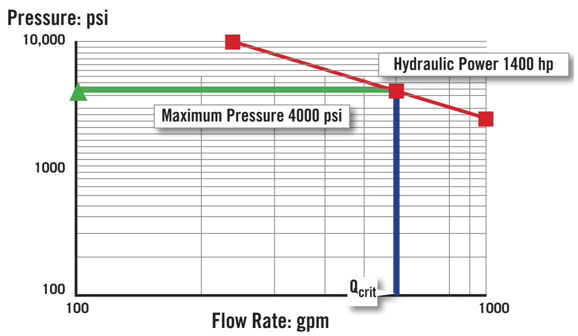


Figure 3-16: Limit conditions for the drilling rig.

3.14.2 Calculate nozzle pressure losses

With the data from the flow tests, calculate the pressure drop through the drill bit and subtract from the standpipe pressure.

The pressure loss through the drill bit may be calculated as a function of flow rate, Q. Table 3-1 indicates the total flow area for the three nozzles is 0.06412 in.^{2}

Table 3-1: Data from the standpipe readings.

Flow Rate: gpm	Standpipe Pressure: psi
575	4,000
550	3,710
500	3,170
450	2,660
400	2,190
350	1,750

$$P_{BIT} = \frac{(MW)\, Q^2}{12{,}042\, (1.03^2)\, (0.06412^2)}$$

3.14.3 Calculate P_{circ} for each flow rate

For each flow rate calculate the pressure loss through the bit nozzles and subtract from the standpipe pressure. This will be the circulating pressure loss in the wellbore.

Table 3-2: Circulating pressure loss in the wellbore.

Flow Rate: gpm	Standpipe Pressure: psi	Pressure Loss thru bit : psi	Circulating Pressure loss; psi
575	4000	695	3305
550	3710	634	3080
500	3170	524	2643
450	2660	425	2233
400	2190	335	1850
350	1750	257	1494

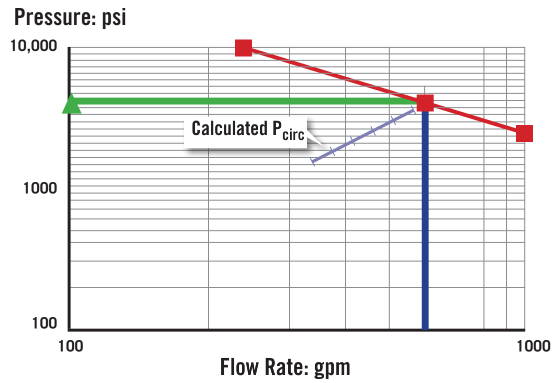


Figure 3-17: Plotting P_{circ} to determine the slope of the line.

3.14.4 Calculate "μ"

To determine the exponent "μ", plot the circulating pressure loss on Figure 3-17 with the pressure limits.

The linear distance between 100 and 1,000 is not the same on the pressure axis as it is on the flow rate axis. The slope cannot be measured properly on this computer generated graph. This means that it must be calculated. The mathematical relationship indicates that the circulating pressure is proportional to flow rate raised to the "μ" power, or:

$P_{circ} = KQ^{\mu}$

Where K is the proportionality constant

To find the values of the two constants (K and μ), two data points are needed to write two equations and solve the simultaneous equations. Examine the curve plotted on Figure 3-17 and select two points which are on the straight line representing the pressure loss through the system. In Figure 3-17, select the pressures 3,080 psi and 1,850 psi for flow rates of 550 gpm and 400 gpm.

$\log P = \log K + \mu \log Q$
$\log 3{,}080 = \log K + \mu \log 550$
$\log 1{,}850 = \log K + \mu \log 400$

Subtract one equation from the other to eliminate the constant K:

$$3.4886 - 3.2672 = \mu\,(2.7404 - 2.6021)$$

$$\mu = \frac{0.2214}{0.1383} = 1.60$$

To determine the constant of proportionality (K), substitute into the equation:

$$P_{circ} = KQ^{\mu}$$

$$3{,}080 = K\,550^{1.6}$$

$$K = \frac{3{,}080}{24{,}243} = 0.127$$

For this well, the circulating pressure loss may be calculated from the equation

$$P_{circ} = 0.127Q^{1.6}$$

3.14.4 Calculate nozzle sizes for maximum hydraulic impact or hydraulic power

With μ=1.6, the optimum pressure loss for the bit can be determined for either the maximum hydraulic impact or the maximum power of the drilling fluid striking the bottom of the hole.

3.14.5 For the maximum force

$$P_{bit\ opt} = \frac{\mu}{\mu + 2} P_{max}$$

The circulating pressure loss is the difference between the standpipe pressure maximum and the bit pressure loss, the circulating pressure loss would be calculated from the equation:

$$P_{circ\ opt} = P_{max} - \frac{\mu}{\mu + 2} P_{max} = \frac{2}{\mu + 2} P_{max}$$

Since $P_{circ\ opt}$ is known as a function of flow rate, the flow rate required to create the proper pressure loss across the bit may be calculated:

$$P_{circ\ opt} = P_{max} - \frac{u}{\mu + 2} P_{max} = \frac{2}{\mu + 2} P_{max}$$

$$Q^{1.6} = \frac{2\,(4{,}000\text{ psi})}{(1.6 + 2)\,(0.127)}$$

Q = 450 gpm

This value agrees with the intersection of the plot of the circulating pressure loss and the optimum value from the calculation (Figures 3-18 and 3-19).

3.14.6 Selecting nozzles for the maximum hydraulic impact with optimum flow rate

The next task is to determine the nozzle sizes which will provide the optimum pressure loss through the drill bit at the 450 gpm flow rate. The pressure loss through the drill bit nozzles should be 1,780 psi to make the standpipe pressure the maximum value of 4,000 psi. The measurements indicate that the pressure loss through the circulating system will be 2,220 psi.

$$P_{bit} = \frac{(MW)\,Q^2}{12{,}042\,(1.03^2)\,(A^2)}$$

$$(A^2) = \frac{(MW)\,Q^2}{12{,}042\,(1.03^2)\,P_{BIT}}$$

$$= \frac{(11\text{ ppg})\,450^2}{12{,}042\,(1.03^2)\,(1{,}780\text{ psi})}$$

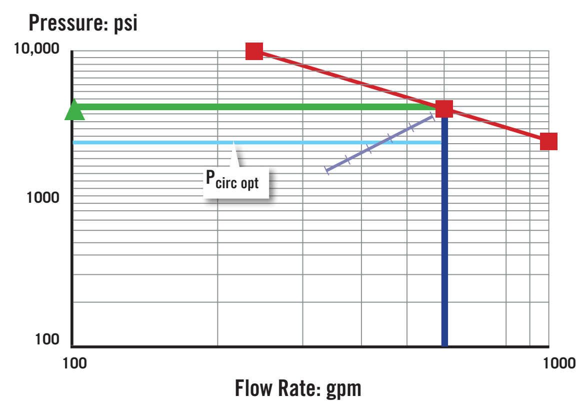
$$= 0.0980\text{ in.}^2$$

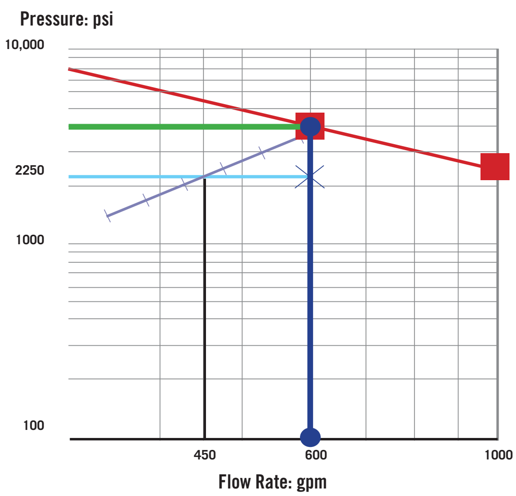
Area = 0.3131 in.^{2} This would call for one 11⁄32-in. nozzle and two 12⁄32-in. nozzles.

3.14.7 Evaluate the increase in hydraulic impact force

The process should result in the drilling fluid striking the bottom of the hole with the maximum force possible. Hydraulic impact force is the product of the mud weight times the flow rate times the velocity.

Calculate the impact force available with the dull bit:





The velocity of the fluid through the two 16⁄32-in. and one 18⁄32-in. nozzles, could be calculated by dividing the flow rate by the flow area of the nozzles:

$$\text{Velocity} = \frac{575\ \frac{\text{gal}}{\text{min}}}{0.6412\ \text{in.}^2}\ \frac{231\ \text{in.}^3}{\text{gal}}\ \frac{\text{ft}}{12\ \text{in.}}\ \frac{\text{min}}{60\ \text{sec}} = 286\ \text{ft/sec}$$

$$\text{Force} = (11.0\tfrac{\text{lb}}{\text{gal}})(575\tfrac{\text{gal}}{\text{min}})\ (286\tfrac{\text{ft}}{\text{sec}})\,(\tfrac{\text{min}}{60\ \text{sec}})\,(\frac{1}{32.2\ \frac{\text{ft}}{\text{sec}^2}}) = 936\ \text{lb}$$

Calculate the impact force for the new bit:

$$\text{Velocity} = \frac{450\ \frac{\text{gal}}{\text{min}}}{0.3131\ \text{in.}^2}\ \frac{231\ \text{in.}^3}{\text{gal}}\ \frac{\text{ft}}{12\ \text{in.}}\ \frac{\text{min}}{60\ \text{sec}} = 461\ \text{ft/sec}$$

$$\text{Force} = (110\tfrac{\text{lb}}{\text{gal}})\ (450\tfrac{\text{gal}}{\text{min}})\ (461\tfrac{\text{ft}}{\text{sec}})\ (\tfrac{\text{min}}{\text{sec}})\,(\frac{1}{32.2\frac{\text{ft}}{\text{sec}^2}}) = 1{,}181\ \text{lb}$$

This additional 245 lb of hydraulic impact force should raise the founder point of the drill bit significantly. This optimization process — of maximizing the hydraulic impact or the hydraulic power — does not guarantee an increase in penetration rate. The process provides a method of removing more cuttings from the bottom of the hole. If these cuttings are not generated, the ability to remove additional cuttings would not increase the drilling rate.

The appendices contain derivations for most of the equations used in the calculations. Once the derivations and formulation of the equations are understood, that material is not needed for application and implementation of the procedure. Appendix 3E contains nozzle areas for a variety of combinations of nozzle diameters. This makes it easier to select nozzles for most areas that are calculated in the procedures.

APPENDICES

Appendix 3A: The meaning of the "μ" exponent

The exponent on the flow rate value indicates the net effect of pressure losses because of laminar and turbulent flow. These different flow regimes are discussed below.

3A.1 Phenomenological analysis of laminar/turbulent flow

Fluid mechanics provides methods for calculating pressure losses through pipes. If honey is flowing extremely slowly in a smooth wall pipe, the pressure loss will be proportional to the flow rate according to Hagan-Poiseuille's Law:

$$\Delta P = \frac{8\mu L V}{R^2} \qquad \textbf{Equation 3A-1}$$

Where:

- ΔP is pressure loss
- μ is viscosity
- L is length
- V is velocity
- Q is flow rate
- R is pipe radius

The flow is laminar if the pipe walls are smooth and without obstructions. Hagan-Poiseuille's Law can be written in terms of velocity, v, instead of flowrate:

$$\Delta P = \frac{8\mu L V}{R^2} \qquad \textbf{Equation 3A-2}$$

In laminar flow, all points across the diameter of a pipe would move parallel to each other. If the fluid wets the surface of the pipe, the first layer of fluid is bound rather tightly to the surface. The outer sections of the flow stream move much more slowly than the center layer.

Although not all fluid is moving with the same velocity, all flow streams are parallel to each other. This is illustrated in Figure 3A-1.

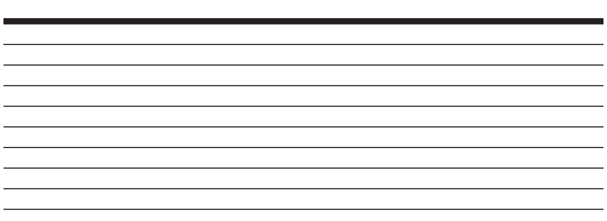


Figure 3A-1: Parallel flow streams in laminar flow.

3A.1.1 Laminar flow

Laminar flow means that all movement will be parallel to the sides of the container and no flow stream will intersect another. Achieving this requires careful planning and, obviously, very smooth sides. In this case the pressure loss along the pipe will depend upon the velocity of the fluid, and the viscosity of the fluid, as indicated by Hagan-Poiseuille's Law. Most drilling fluids are Non-Newtonian. The viscosity depends upon the shear rate, as discussed in Appendix 3F.

3A.1.2 Turbulent flow

Turbulent flow is much more complicated than simple laminar flow. Although the fluid is moving down a pipe, some components of the fluid are also moving in many other directions. A fluid at rest will not move unless a pressure is applied. This means that in a turbulent flow situation, many small pressure differentials are developed within the fluid which allows the fluid to flow in directions other than the direction of the main flow pattern.

The most common consideration to determine pressure losses of a Newtonian fluid flowing in a pipe begins with the calculation of Reynolds number. The dimensionless Reynolds number is a ratio of the inertia forces per unit area divided by the viscous forces per unit area:

$$R_e = \frac{\rho V L}{\mu} \qquad \textbf{Equation 3A-3}$$

Where

- R_e is Reynolds number,
- ρ is density,
- V is velocity,
- L is length,and
- μ is viscosity

As the viscous forces diminish compared to the inertial forces, the Reynolds number increases. In circular pipes, turbulence is damped out if R_e is less than 2,000. For R_e from 2,000 to about 4,000, the flow is called transitional. For R_e above 4,000 the flow is considered turbulent. Another way to look at these numbers is to say when the inertial forces per unit area are less than 2,000 times the viscous forces, the flow will be considered laminar. When the inertial forces are greater than 4,000 times the viscous forces, the flow is turbulent.

However, the Reynolds number is not accurately calculated for shear thinning fluids like drilling fluids. A more complicated Hedstrom number must be used to judge whether the fluid is flowing in turbulent or laminar flow.

In laminar flow, fundamental laws produce a result that can be confirmed by experiments. Turbulent flow, however, is much more complicated. For example, at high Reynolds numbers the disruption of the laminar film adjacent to the wall of a pipe renders viscous action negligible. The velocity distribution and friction factors depend upon the magnitude of roughness or discontinuities in flow patterns rather than only the Reynolds number as in smooth pipes.

Head loss (h) in a pipe may be calculated from Darcy's equation:

$$\frac{h}{l} = \frac{6 f v^2}{gd}$$ **Equation 3A-4**

Where:

l is pipe length, ft
f is the friction factor
v is velocity, ft/sec
g is the acceleration of gravity, ft /sec^2
d is the internal diameter of the pipe, in .

For turbulent flow the friction factor is a function of Reynolds number (R_e):

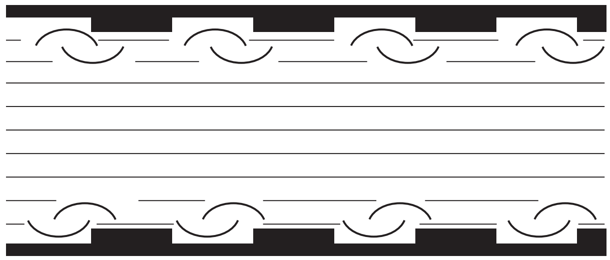
$$f = \frac{0.184}{(R_e)^{0.2}}$$ **Equation 3A-5**

The exponent of 0.2 on Reynolds number means that the effect of density and viscosity on head loss is small.

Actually, both the viscous forces and the inertial forces continue to contribute to the pressure losses in a pipe. This reveals the real problem of trying to calculate pressure losses for Non-Newtonian flow inside of drillpipe. At each tool joint, there is a turbulent initiator. The pressure loss in the turbulent zone will be proportional to the velocity squared. In other regions where the flow is not turbulent, the fluid viscosity will dominate and the pressure loss depends more on the fluid viscosity. In Non-Newtonian flow, the viscosity varies with shear rate and, of course, temperature. Predicting where these transitions will occur is almost impossible, consequently precise calculations would be difficult to achieve.

The pressure loss for laminar flow is proportional to velocity and for turbulent flow the pressure loss is proportional to the square of the velocity. Viscosity does not appreciably affect the pressure calculation in turbulent flow.

As fluid moves through a conduit, some disruption in the laminar flow streams is entirely possible, depending upon the velocity of the flow and the nature of the walls of the



Discontinuities cause turbulence

Figure 3A-2: Initiating turbulence.

conduit. In the regions where flow is disrupted, viscous forces are less important than inertial forces. Consequently, the pressure loss in a pipe might be a function of the velocity or flow rate raised to an exponent between one and two.

Summary

With laminar flow, the pressure drop will be a function of the velocity and the viscosity of the fluid. With turbulent flow, the pressure loss will be independent of viscosity and depends on the density and the square of the velocity.

What happens when there is a blend of the two types of flow? Suppose a pipe has discontinuities along the walls as shown in Figure 3A-2.

How can the pressure loss through this pipe be calculated? Most of the pressure loss will be proportional to the velocity (or flow rate) and viscosity; however, some components of the flow are producing pressure losses proportional the square of the velocity and to some fraction of the viscosity. The degree of turbulence in the flow stream is dependent upon the magnitude of the disruptions as well as the damping effect that Non-Newtonian flow properties can exert.

One of the problems with predicting pressure losses in wellbores is the fact that not all of the variables are known. For example CONSIDER: A fluid is flowing at 5 gal/min within a 4-in. inside diameter, 100-ft long pipe. What is the pressure loss in the pipe? In this simple example, the fluid description is absent from the problem specifications. Would it make a difference if the fluid is water, alcohol, or honey? Why? Obviously, the viscosity of the fluid would have a big impact on the pressure loss in laminar flow.

On a drilling rig, the rheological properties of a drilling fluid are measured at either 120° F or sometimes at 50°F (for deepwater wells) or 150° F (for an oil-based drilling fluid in a hot hole). Unfortunately, rheological properties cannot be accurately predicted at other temperatures (and pressures) from measurements made at one temperature.

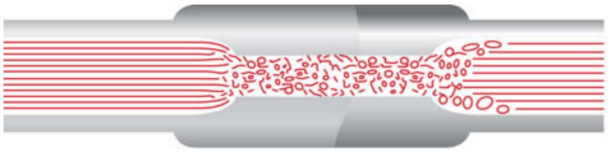


Figure 3A-3: Turbulence created by tool joints.

Second, the flow rheology is unknown in a wellbore. When fluid is flowing in laminar flow in a pipe, the pressure drop in a pipe is proportional to the flow rate and the viscosity of the fluid. When fluid is flowing in turbulent flow, the pressure drop in a pipe is proportional to the 1.9 power of the flow rate and the 0.2 power of viscosity. Within a drill string, tool joints disrupt the flow profile between each joint. In a very viscous drilling fluid, very little turbulence may be experienced; in a very low viscosity fluid, a lot of turbulence may be experienced. The induced turbulence would not necessarily continue throughout the pipe joint. A very low viscosity fluid would allow the turbulence to propagate down the drillpipe much further than a highly gelled drilling fluid. So the pressure drop through drillpipe should be proportional to flow rate raised to some exponent between 1 and 2, inclusive. The viscosity of the fluid would be important in the laminar part of the flow stream. These values cannot be predicted with any certainty before the well is drilled because the viscosity and flow behavior of the fluid depends upon the ingredients in the drilling fluid, as well as the temperature.

Many hydraulic programs assume an exponent "μ" (on flow rate) of around 1.82 to 1.85. This range of values is based on measurements made shortly after the Second World War. A better solution would be to measure the effect at the rig site and use the wellbore as a rheometer. This "rig-measured exponent" will include all of the unusual features within the circulating system (large diameters, small diameters, changes in viscosity with pressure and temperature, changes in flow regimes, etc.).

Pressure losses of a liquid flowing through a conduit has another interesting feature: when the flow is fully turbulent as through jet nozzles, the pressure loss is dependent upon the mud weight and the square of the velocity. The actual low shear rate viscosities have very little effect. When the fluid is flowing in laminar flow, with no turbulence, the pressure loss is dependent upon the viscosity of the fluid at the particular shear rate within the conduit. Inside of a drill string, the tool joints and the other components may create a turbulent zone. The pressure loss through this interval would be proportional to the square of the velocity. As the turbulence diminishes, the pressure loss becomes proportional to the velocity and the viscosity of the fluid. The viscosity of a drilling fluid depends upon the shear rate and the temperature. With a water-base drilling fluid, the viscosity is not affected by pressure. In a non-aqueous fluid (NAF), the pressure as well as the velocity and temperature will affect the pressure loss.

The above discussion explains why computer programs have so much difficulty predicting nozzle sizes before spud.

The problem arises when calculating the pressure loss through a drillpipe. At each tool joint, a discontinuity in the flow stream can create a region of turbulence. The pressure loss through the drill string will be some function (f) of a combination of laminar and turbulent flow pressure losses:

$$\text{Pressure loss/length} = f\,(x\,P_{lam}\,,\, y\,P_{turb}\,) \qquad \textbf{Equation 3A-6}$$

Where x is the fraction of pressure loss in laminar flow and y is the fraction of pressure loss in turbulent flow.

The amount of turbulent flow will depend upon the shape of the flow path and the fluid characteristics. If the fluid has a very low viscosity at the shear rates imposed, the turbulent zone will propagate a long distance down the next section of drill pipe. If the fluid has a very high viscosity, the turbulent zone will be damped rather quickly. The viscosity of a non-Newtonian fluid varies considerably with temperature, shear rate, and the exact ingredients in the fluid. The amount of damping will be almost impossible to predict.

Because the major component of pressure loss through nozzles seems to be the turbulent component, the kinetic energy equations are usually modified for calculating pressure losses in the drill string. With fully turbulent flow, the pressure loss is proportional to the flow rate (or velocity) squared. Computer programs use a flow rate exponent of 1.86 to compensate for the fact that the flow is not fully turbulent and not completely laminar. This exponent can be measured at the rig and exponents have ranged from 1.4 to 1.9. This technique to determine this exponent was published in 1982, and modified for longer bit runs in 2001.[1]

Appendix 3B: Maximum hydraulic force and power

Discussion of the optimum flow rate to cause the fluid to strike the bottom of the hole with the most force (or impact) or expend the most power.

The equations for maximum hydraulic force or maximum hydraulic power are derived for the limiting conditions imposed by the drilling rig. Either the impact force or the hydraulic power can be maximized to use as a criterion for optimization. Searching the literature for years has failed to reveal valid correlative investigations that confirm one method is better than the other to improve drilling rates. Both will be presented here.

3B.1 Introduction to derivations

Derivation of the equations for the hydraulic force (or impact) or the hydraulic power of the fluid passing through the nozzles.

Hydraulic impact is a force F that is the mathematical product of the fluid density, ρ, flow rate, Q, and velocity, v. With suitable conversion units, the force may be expressed in pounds, kilograms, or newtons of force using the equation:

$$F = \rho\, Qv \qquad \textbf{Equation 3B-1}$$

Hydraulic power, HP, may be calculated by multiplying the force, F, by the velocity of the fluid, v; or

$$HP = F\, v = \rho\, Qv^2 \qquad \textbf{Equation 3B-2}$$

Both techniques will require calculating the force with which the fluid strikes the bottom of a hole. This force can be related to the pressure drop through the nozzles; as shown in the derivation below:

3B.2 Derivation of equations to create the maximum hydraulic impact force

Newton's Second Law of Motion, F = ma, can also be expressed as a change in momentum since the acceleration is a rate of change of velocity, or:

$$F = \frac{mv_2 - mv_1}{t} \qquad \textbf{Equation 3B-3}$$

The fluid moving downward toward the bottom of a hole starts with a velocity V_2 and is stopped by the bottom of the hole from further downward movement, i.e., $V_1 = 0$. The mass flow rate, or m/t, could be expressed as the product of the fluid density, ρ, and the flow rate, Q. The equation then becomes:

$$F = \rho\, Qv \qquad \textbf{Equation 3B-4}$$

The pressure loss through a nozzle, ΔP, can be expressed as:

$$\Delta P_{bit} = \frac{\rho\, Q^2}{K^1\, A^2} \qquad \textbf{Equation 3B-5}$$

This equation is derived in Appendix 3C.

Since Q/A is velocity, the equation can be written:

$$\Delta P_{bit} = \frac{\rho\, v^2}{K^1} \qquad \textbf{Equation 3B-6}$$

This equation can be solved for the velocity and that term substituted into the force equation.

$$v = \sqrt{\frac{K^1\, \Delta P_{bit}}{\rho}} \qquad \textbf{Equation 3B-7}$$

Since force is ρ Qv, then force must also be:

$$F = Q\sqrt{K^1\, \rho\, P_{bit}} \qquad \textbf{Equation 3B-8}$$

The density is a constant so it can be combined with the other constants in the equation and gives the expression for force:

$$F = KQ\,(\Delta P_{bit})^{0.5} \qquad \textbf{Equation 3B-9}$$

This expression is used to develop the mathematical relationships which will maximize the hydraulic impact or power, as shown below.

The pressure loss through the system will be related to flow rate raised to an exponent between one and two. This exponent, μ, is unique for every well and is characteristic of the well at the time it is determined. Stated another way, this characteristic exponent will change over the life of the well and hence must be determined for each bit independently.

3B.3 Maximizing hydraulic impact

Two separate regimes exist for maximizing the force with which the fluid strikes the bottom of the hole. The first regime is where the maximum standpipe pressure is limited by the rig's available hydraulic power. Pumps are operated by connecting to motors. If small motors drive pumps, very little power will be available for pumping fluid. This regime occurs at the shallower depths where the optimum flow rate is high. Each drilling rig has a maximum possible standpipe pressure. The limit might be the pressure ratings of the pump liners, contract limitations, or a pressure-limiting bubble in the rotary hose. This is the second regime. Between these two regimes, the hydraulic impact will be limited by both the hydraulic power and the maximum standpipe pressure.

The pressure loss through the drilling fluid circulating (P_{circ}) system can be expressed as $P_{circ} = KQ^{\mu}$, where K is a constant, Q is the flow rate, and μ is the exponent. If the flow is turbulent, μ = 2. The standpipe pressure (P_{surf}) can be expressed as the sum of two pressure losses: P_{circ} and P_{bit}.

The maximum hydraulic impact depends upon the limiting conditions from the drilling rig. The obvious limiting hydraulic condition will be the amount of power available to drive the mud pumps. The second limiting condition will be the maximum standpipe pressure. Each of these conditions will be discussed and the equations derived to cause the fluid to strike the bottom of the hole with the greatest force possible.

3B.3.1 Maximum hydraulic impact for the power limited case

On a drilling rig, the mud pumps are powered by motors with a finite amount of power. Generally, the hydraulic power can be obtained by assuming a mechanical efficiency of power transfer of about 85% and a volumetric efficiency of 93% to 95%. So the mathematical relationship would be: When calibrating the pump flow rate with stroke rate, the actual volumetric efficiency can be calculated.

$$HHP = (E_m)\,(E_v)\,(\text{motor horsepower}) \qquad \textbf{Equation 3B-10}$$

When calibrating the pump flow rate with stroke rate, the actual volumetric efficiency can be calculated.

This hydraulic horsepower is also the product of the surface (or standpipe) pressure and the flow rate.

$$HHP = \frac{(P_{surf})\,(Q)}{1{,}714} \qquad \textbf{Equation 3B-11}$$

Where:

HHP is the hydraulic horsepower, hp
P_{surf} is the surface (or standpipe) pressure, psi
Q is the flow rate, gpm

For the hydraulic case where the limit condition is the available hydraulic power on the drilling rig, the limit condition could be expressed as:

$$HHP = (P_{surf})\,(Q) = \text{constant} = C \qquad \textbf{Equation 3B-12}$$

Since the standpipe (or surface) pressure consists of the sum of two components, P_{surf} can be written as:

$$P_{surf} = P_{circ} + P_{bit} \qquad \textbf{Equation 3B-13}$$

This can also be written:

$$\frac{HHP}{Q} = P_{circ} + P_{bit} \qquad \textbf{Equation 3B-14}$$

Solving this equation for P_{bit} and expressing P_{circ} in terms of Q and u:

$$P_{bit} = \frac{HHP}{Q} - KQ^{\mu} \qquad \textbf{Equation 3B-15}$$

The expression derived which related the hydraulic impact (force) to the pressure drop through the bit nozzles was:

$$F = KQ[P_{bit}]^{0.5} \qquad \textbf{Equation 3B-16}$$

This force may now be calculated in terms of flow rate from the calculation for the pressure drop through the bit nozzles:

$$F = KQ\left[\frac{HHP}{Q} - KQ^{\mu}\right]^{0.5} \qquad \textbf{Equation 3B-17}$$

Or, rearranging terms:

$$F = K\,[Q(HHP) - KQ^{\mu+2}]^{0.5} \qquad \textbf{Equation 3B-18}$$

This is the expression for the force of the fluid striking the bottom of the hole. To find the maximum value, differentiate with respect to flow rate and set the differential equal to zero.

$$\frac{\partial F}{\partial Q} = \frac{K\,(HHP - K\,(\mu+2)\,Q^{\mu+1})}{(Q\,(HHP) - KQ^{u+2})^{0.5}} = 0 \qquad \textbf{Equation 3B-19}$$

For this to be true, the numerator must be equal to zero or

$$HHP = K\,(\mu+2)\,(Q_{opt})^{\mu+1} \qquad \textbf{Equation 3B-20}$$

Since HHP is the product of the standpipe pressure and the flow rate,

This could be written as

$$\left[\left(P_{surf\,opt}\right)(Q_{opt})\right] = K\,(\mu+2)\,(Q_{opt})^{\mu+1} \qquad \textbf{Equation 3B-21}$$

Solving for the optimum surface (or standpipe) pressure, results in:

$$P_{surf\,opt} = k\,(\mu+2)\,(Q_{opt})^{\mu} \qquad \textbf{Equation 3B-22}$$

The pressure loss through the circulating system was

$$P_{circ} = K\,Q^{\mu} \qquad \textbf{Equation 3B-23}$$

The optimum surface (or standpipe) pressure would therefore be:

$$P_{\underset{opt}{surf}} = (\mu+2)\left(P_{\underset{opt}{circ}}\right) \quad \textbf{Equation 3B-24}$$

The optimum pressure drop through the bit nozzles would be the difference between the optimum surface pressure and the optimum circulating pressure, or:

$$P_{\underset{opt}{bit}} = \left(1 - \frac{1}{\mu+2}\right) P_{\underset{opt}{circ}} \quad \textbf{Equation 3B-25}$$

This can also be written:

$$P_{\underset{opt}{bit}} = \left(\frac{\mu+1}{\mu+2}\right) P_{\underset{opt}{circ}} \quad \textbf{Equation 3B-26}$$

If the (μ+1/μ+2) fraction of the standpipe pressure is applied across the jet nozzles, the hydraulic impact will be the maximum value possible for the hydraulic power limited case.

3B.3.2 Surface pressure limit

As wells get deeper, the limits on surface pressure prevents utilization of all available hydraulic power. The surface pressure becomes the limiting condition. The pressure drop through the bit nozzles would be the difference in pressure between the maximum standpipe pressure, P_{max}, and the circulating pressure drop, P_{circ}:

$$P_{bit} = P_{max} - P_{circ} \quad \textbf{Equation 3B-27}$$

The circulating pressure loss, P_{circ}, is proportional to the flow rate, Q, raised to an exponent, μ, or:

$$P_{circ} = K\,Q^{\mu} \quad \textbf{Equation 3B-28}$$

The hydraulic impact force, F, derived earlier, is related to the pressure drop across the bit nozzles, or;

$$F = KQ\,[P_{bit}]^{0.5} \quad \textbf{Equation 3B-29}$$

Again, to maximize the force with respect to flow rate, the force equation (expressed in terms of flow rate) must be differentiated and the differential set equal to zero.

$$F = KQ\,[P_{max} - P_{circ}]^{0.5} \quad \textbf{Equation 3B-30}$$

$$F = KQ\,[P_{max} - K'Q^{\mu}]^{0.5} \quad \textbf{Equation 3B-31}$$

$$F = K\,[Q^2 P_{max} - K'Q^{\mu+2}]^{0.5} \quad \textbf{Equation 3B-32}$$

$$\frac{\partial F}{\partial Q} = \frac{K\,(2QP_{max} - K'(\mu+2)\,Q^{\mu+1})}{(Q^2 P_{max} - K'Q^{\mu+2})^{0.5}} = 0 \quad \textbf{Equation 3B-3}$$

For this to be true, the numerator must be equal to zero; or:

$$2QP_{max} = K'(\mu+2)\,Q^{\mu+1} \quad \textbf{Equation 3B-34}$$

$$P_{max} = \left(\frac{\mu+2}{2}\right) K'Q^{\mu} \quad \textbf{Equation 3B-36}$$

$$P_{max} = \left(\frac{\mu+2}{2}\right)\left(P_{\underset{opt}{circ}}\right) \quad \textbf{Equation 3B-37}$$

Since

$$P_{bit} = P_{max} - P_{circ} \quad \textbf{Equation 3B-37}$$

$$P_{\underset{opt}{bit}} = P_{max} - \left(\frac{2}{\mu+2}\right) P_{max} \quad \textbf{Equation 3B-38}$$

or

$$P_{\underset{opt}{bit}} = \left(\frac{\mu}{\mu+2}\right) P_{max} \quad \textbf{Equation 3B-39}$$

3B.4 Derivation of equation for maximum hydraulic power at bit

To find the maximum hydraulic power available at a drill bit for any flow rate, the expression for hydraulic power must be differentiated with respect to flow rate and the derivative set equal to zero.

Hydraulic horsepower at the bit has been expressed by the equation:

$$HHP_{bit} = K''PQ = K'(P_{max} - P_{circ})Q \quad \textbf{Equation 3B-40}$$

The circulating pressure loss is proportional to the flow rate raised to the exponent u power. Substituting this into the HHP equation results in:

$$\begin{aligned} HHP_{bit} &= K''(P_{max} - KQ^{\mu})Q \\ &= K''(QP_{max} - KQ^{\mu+1})Q \end{aligned} \quad \textbf{Equation 3B-41}$$

Differentiating this equation with respect to the flow rate, Q:

$$\frac{\partial(HHP)}{\partial Q} = K''[P_{max} - K(\mu+1)Q^{\mu}] = 0 \quad \textbf{Equation 3B-42}$$

Since "K" is not zero, the term in the bracket must be zero, or, for optimum conditions:

$$P_{max} = (\mu+1)\,(KQ_{opt}^{\ \mu}) = (\mu+1)\left(P_{\underset{opt}{circ}}\right) \quad \textbf{Equation 3B-43}$$

The optimum pressure loss through the bit would be the difference between the maximum standpipe pressure (P_{max}) and the optimum circulating pressure loss (P_{circ}), or:

$$P_{bit_{opt}} = P_{max} - P_{circ_{opt}} = \left[1 - \frac{1}{\mu+1}\right] P_{max} = \left[\frac{u}{\mu+1}\right] P_{max}$$

Equation 3B-44

Appendix 3C: Calibrating mud pumps

Rig pumps should be calibrated while pumping at normal circulating pressures. Pumping fluid from the drilling fluid system into a trip tank, with no back pressure, will give a false value for the pump volumetric efficiency. Most drilling fluid surface systems have a small compartment, or slug tank, that is used for pumping a heavy weight drilling fluid into the drill pipe before tripping or is used for mixing sweeps of viscous fluid to clean the hole. Measure the dimensions of the cross-sectional area of the slug tank and calculate the volume of the tank per vertical inch of the tank. One gallon is 231 cu in.

Fill the slug tank, or small compartment in the surface drilling fluid with drilling fluid. While drilling, switch the pump suction from the normal suction tank to the slug tank. After the liquid level drops about six to 10 inches start timing the decrease in liquid level. Determine the volume of fluid pumped during the measured time period.

Normally, the fluid in the slug tank will have both liquid and gas in it. The gas will be compressed by the rig pumps to virtually no volume. Use the equation below to determine the volume percent of gas in the drilling fluid:

$$\%\ gas = \frac{\text{Pressurized mud weight-unpressurized mud weight}}{\text{Pressurized mud weight}}\ 100$$

Equation 3C-1

Frequently, the pressurized mud weight is not available. In this case, add a defoamer to the drilling fluid in a mud cup. Pour the fluid through a marsh funnel viscometer about three times to blend and then measure the mud weight on a regular rig mud balance. The mud weight should be within about 0.05 ppg of the pressurized mud weight. Determine the volume of gas pumped and subtract it from the total volume of fluid leaving the slug pit. As little as 6% volume of gas has reduced the volumetric pump efficiency from 97-85% volume. This value also does not always stay constant during any 24-hour period, depending upon formations being drilled.

This procedure must be coordinated with the driller. Removing fluid from the circulating system to fill the slug tank will appear to be a lost circulation problem to the driller. When the pump suction is switched to from the normal active drilling fluid system to the slug tank, the pit levels in the active system will rise. The driller may interpret this as a kick and stop drilling.

This procedure may be easily repeated two or three times without interfering with the normal drilling operations.

Appendix 3D: Nozzle pressure loss calculations

Pressure is energy per unit volume. For a standing liquid, the energy is calculated from potential energy equations. For flowing fluids, pressure is calculated from kinetic energy equations.

3D.1 Potential energy

Pressure in a liquid, or stress in a solid, is the energy per unit volume. For example, in a static column of fluid, the pressure at any depth is the potential energy per unit volume at that depth.

$$\text{Pressure} = \frac{\text{Potential Energy}}{\text{Volume}}$$

Equation 3D-1

Potential energy may be calculated from the equation:

Potential energy = mgh

Where:

- m is the mass
- g is the acceleration of gravity
- h is the depth of fluid, or the height above the point of interest.

Pressure would be:

$$\text{Pressure} = \frac{mgh}{\text{Volume}}$$

Equation 3D-2

From Newton's Second Law of Motion:

$$W = mg$$

Equation 3D-3

Where W is weight, or the force applied to a body by the gravitational attraction.

A ratio of weight to volume is called density, ρ. The equation for pressure becomes:

$$\text{Pressure} = \rho h$$

Equation 3D-3

To convert the units to oilfield variables and calculate pressure in pounds per square inch, ρ should be expressed as pounds per gallon and h in feet.

$$\text{Pressure} = \text{MW}\left(\frac{\text{lb}}{\text{gal}}\right)\left[\frac{\text{gal}}{231\ \text{in.}^3}\right]\{\text{h, ft}\}\left[\frac{12\ \text{in.}}{\text{ft}}\right]$$

Equation 3D-4

This equation reduces to the familiar equation used extensively in well control:

Pressure = 0.052 (MW, ppg) (depth, ft) **Equation 3D-5**

3D.2 Kinetic energy

Pressure in a flowing liquid can be described as kinetic energy (KE) per unit volume.

P = KE/volume **Equation 3D-6**

$$P = \frac{\tfrac{1}{2}\,mv^2}{\text{volume}}$$ **Equation 3D-7**

$$P = \tfrac{1}{2}\left(\frac{m}{\text{volume}}\right)v^2$$ **Equation 3D-8**

Where:

P is the pressure
m is the mass
v is the velocity of the fluid

Weight per unit volume is density (ρ)
Newton's Second Law: Weight = mg

Substituting this into the equation results in:

$$P = \tfrac{1}{2}\left(\frac{\rho}{g}\right)v^2$$ **Equation 3D-9**

This can be converted to oilfield units where the density is in pounds per gallon, and the velocity is expressed by a ratio of flow rate (Q, in gpm) and area (in square inches).

$$P = \frac{(\text{MW})(Q^2)}{12{,}032\,(A^2)}$$ **Equation 3D-10**

where the value of g is selected as 32.17 ft/sec^2.

This pressure is a function of the density of the fluid, and the square of the velocity (Q/A).

3D.3 Nozzle pressure loss analogy

Before discussing nozzle pressure losses, consider flow through a pipe connected to a tank of liquid with a constant head. Calculate the pressure in the pipe at Points A, B, C, D, and E using the kinetic energy equation used to calculate pressure losses through nozzles.

The velocity along the pipe is constant because the flow rate is the same at all points. The mass moving through the pipe is constant. Consequently, the kinetic energy (½ mv^2) is constant along the length of pipe. Pressure is kinetic energy per unit volume. The pressure (or kinetic energy) at Points B, C, D, E, and G will be the same. Obviously, a pressure loss occurs along the pipe and is dependent upon whether the flow is laminar or turbulent.

The nozzle pressure loss equation currently used is derived from the equation:

Pressure equals Kinetic Energy per unit Volume

The density (mass/volume) is unchanged along the length of pipe. The pressure calculated from kinetic energy would be constant. With a constant pressure all along the length of pipe, the flow rate would be independent of pipe length.

However, the pressure inside of the pipe decreases along the pipe as the fluid flows from the high pressure end to the low pressure end. Obviously, another term is required to properly calculate the pressure inside of the pipe at all points. This equation does not consider the entrance and exit losses in a nozzle. The pressure at the bottom of the standpipe can be calculated from potential energy. As the fluid moves into the pipe, the constriction of flow streams results in a pressure loss. This is typically called a "velocity head loss" and is commonly observed in centrifugal pump curves. As the fluid exits the large diameter cylinder, the pressure may be calculated from the kinetic energy equation as discussed above. All along the pipe, however, the pressure is decreasing. As the fluid exits the pipe, the exit is submerged in a tank of fluid and there will be an exit loss.

3D.4 Nozzle pressure analogy

This example could also be related to what happens as drilling fluid flows through drill bit nozzles. Inside of the bit, the flow is diverted from a large diameter area into very small di-

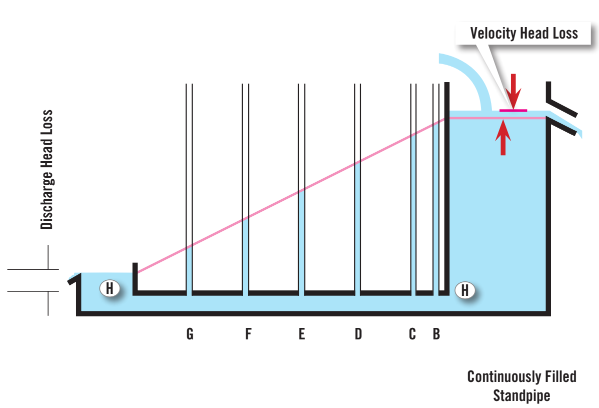


Figure 3D-1: Constant head flow through horizontal pipe.

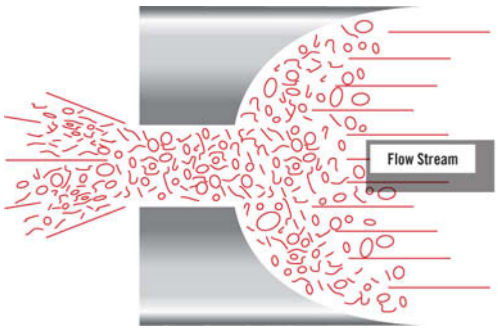


Figure 3D-2: Sketch of jet nozzle. Kinetic energy is calculated at point B to develop equation for calculating bit pressure loss.

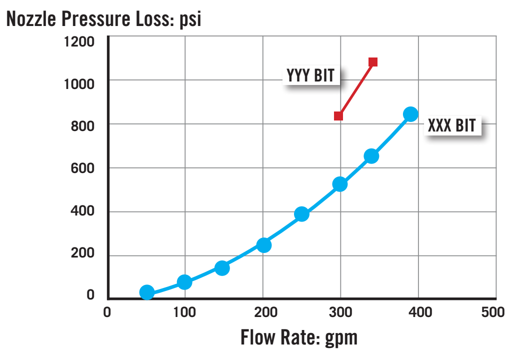


Figure 3D-3: Smooth increases in pressure losses through nozzles.

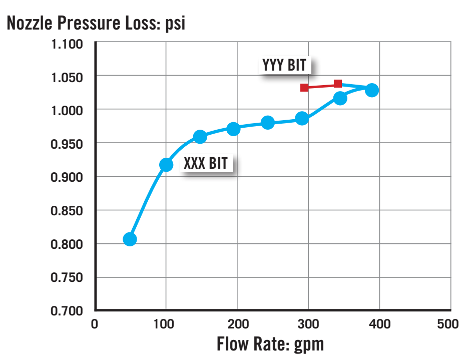


Figure 3D-4: Smooth increases in pressure losses through nozzles.

ameter jets [like the bottom of the large diameter cylinder]. A 'velocity head' loss occurs. As the fluid flows through the nozzles, a significant reduction in pressure occurs (as shown by the flow through the pipe). The fluid exits the nozzle, strikes the bottom of the hole and reverses direction to flow up the annulus [similar to the pressure loss caused by the tank of liquid at the end of the pipe]. In a nozzle, three pressure losses comprise the total pressure loss through the nozzle: A. Entrance loss; B. Through nozzle loss; and H. Exit loss. Depending upon the shape of the flow leaving the nozzle, some pressure recovery is possible as the velocity head becomes a pressure head. This pressure recovery is frequently used to carry fluid from mud hoppers up over the walls of mud tanks. It requires a gradual transition from one small diameter (the nozzle) to the pipe carrying the fluid. In drilling fluids, this same effect has been observed after the fluid leaves the nozzles.

The analysis described above has be extended to describe flow through bit nozzles. Nozzle pressure losses are normally measured from a point just above the drill bit inside of the drill string to a point in the annulus just above the drill bit. Most of the flow will be turbulent, but some components may also have characteristics of the laminar flow pressure losses.

Usually, the pressure loss through nozzles is calculated from kinetic energy equation with the addition of a nozzle coefficient, C_d, in the denominator:

$$P = \frac{(MW)\,(Q^2)}{12{,}032\,(C_d)^2\,(A^2)}$$

Equation 3D-11

Where:

P is the pressure loss through the nozzles
MW is the mud weight
Q is the flow rate
C_d is the nozzle coefficient
A is the total flow area of the nozzles

This equation indicates that the pressure loss is proportional to the square of the flow rate.

3D.5 Nozzle coefficient

During tests trying to develop a bit-bearing monitor, the opportunity appeared to experimentally determine the nozzle coefficient for a drill bit. A bit-bearing monitor was installed in two bits by different manufacturers. A facility was rented which provided the opportunity to drill very hard rock (taconite and granite) until the bearings failed in the drill bit. An ambient pressure of 3,000 psi was maintained at the bottom of the borehole. To decrease the cost of the experiments, a seal was not installed in one of the cones in each drill bit. A 10.1 ppg, water–based, gel/lignosulfonate drilling fluid was used for these tests. To assist a more rapid failure, 3% volume sand (distribution of 1.5% vol. 75 mesh and 1.5% vol. 120 mesh) was added to the drilling fluid. Surprisingly, over 8 hours of drilling was required before the bearings failed. During these tests, the pressure inside and outside of the bit and the flow rate through the bit were accurately measured. The nozzles were calipered to provide an accurate nozzle area calculation. All parameters were measured except for the nozzle coefficient, C_d.

Table 3D-1: Nozzle TFA.			
Mfg.	Nozzle Diameter, in.	Nozzle Area, in.^{2}	TFA in.^{2}
XXX	0.3950	0.12225	
	0.4000	0.12566	
	0.4035	0.12787	0.376
YYY	0.3390	0.09026	
	0.3370	0.08920	
	0.3400	0.11254	0.2920

The nozzles were nominal 13⁄32-in. (or 0.4063 in.) in the XXX bit and nominal 11⁄32-in. (or 0.3475 in.) in the YYY bit. The difference in the calipered diameter and the nominal diameter is within the tolerance for nozzles, BUT makes a very large difference in the calculation since the diameter is raised to the fourth power.

3D.5.1 Data

The flow rate was changed in relatively small steps while measuring the pressure drop across the nozzles while drilling with the XXX bit. The nozzle coefficient "C_d" was not constant, but increased significantly when the flow rate increased (Table 3D-1). The flow rate was not varied over a large range of values while drilling with the YYY bit.

There are four components of the pressure to consider: entrance and exit losses, through the nozzle loss, and the pressure recovery factor as the fluid exits into the wellbore. At a low flow rate, the pressure recovery factor is small and the entrance and exit losses dominate. The total pressure loss through the nozzle is higher than the kinetic energy component of the pressure loss. The nozzle coefficient is less than one. When the flow rate is increased, the pressure recover factor is larger than the entrance and exit losses. The total pressure loss is less than calculated by the kinetic energy equation. This is the reason the 1.03 nozzle coefficient should be used while drilling.

The nozzle coefficient, C_d, is used as a "finagle factor" to correct the pressure loss calculation. A value of 1.03 has been measured in two different independent laboratories and validated in field measurements with wire line telemetry. Not all bit companies are using this corrected value.

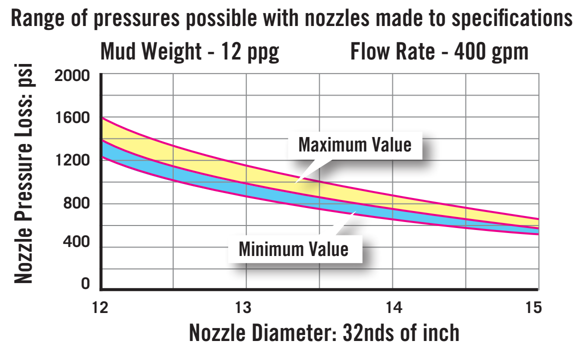


Figure 3E-1: Inaccuracies in pressure losses through nominal bit nozzles.

Appendix 3E: Areas for various nozzle combinations

Table 3E-1 provides cross-sectional areas of a variety of combinations of nozzles.

3E.1 Nozzle size inaccuracy

Nozzles are usually measured in 32nds of an inch. The tolerances on these, however, are one half the 32nd of an inch. The difference in the calipered diameter, and the nominal diameter is usually within the tolerance; however, the difference can make a huge difference in the calculation of pressure loss, since the diameter is raised to the fourth power.

As an illustration of the importance of this calculation importance, Figure 3E-1 indicates the range of error possible for a variety of different nozzle diameters. Pressure losses depend upon the fourth power of the bit diameter. If a 12.0-ppg drilling fluid is pumped through three nozzles at a rate of 400 gpm, the pressure loss through the nozzles is calculated for three under size, three over size and three accurate nozzles. For three 12's, the pressure loss could be 1,600 psi or 1,200 psi. The range of differences becomes smaller as the nozzle sizes increase. The error is still significant.

As an alternate condition, consider matching pressure drop calculations with standpipe pressures to validate the calculations. The process was to calculate pressure losses in surface equipment (relatively small), pressure losses inside drill strings, through nozzles, and up the annulus. The sum of these numbers sometimes matched reported daily report pressures. Problem: annular pressure losses calculated to be 30-40 psi were actually measured in the 300-400-psi range AND the pressure loss through the nozzles was around 300-400 psi less than calculated. Jumping to conclusions is a great exercise for too many engineers.

Table 3E-1: Flow area for various nozzle combinations.

Nozzle Combinations. Sizes in 1/32-in.										Area, in.^{2}
One	Two		Three			Four				
7										0.037583
8										0.049087
9										0.062126
	7	7								0.752
10										0.076699
	7	8								0.867
11										0.092806
	8	8								0.0982
12										0.110447
	8	9								0.1112
			7	7	7					0.1127
	9	9	7	7	8					0.1243
13										0.129621
			7	8	8					0.1358
	9	10								0.1388
			8	8	8					0.1473
14						7	7	7	7	0.150330
	10	10								0.1534
			8	8	9					0.1603
						7	7	7	8	0.1618
	10	11								0.1695
15										0.172673
			8	9	9	7	7	8	8	0.1733
						7	8	8	8	0.1848
	11	11								0.1856
			9	9	9					0.1854
16						8	8	8	8	0.196350
			9	9	10					0.2010
	11	12								0.2033
						8	8	8	9	0.2094
			9	10	10					0.2155
	12	12								0.2209
						8	8	9	9	0.2224
			10	10	10					0.2301
						8	9	9	9	0.2355
	12	13								0.2401
			10	10	11					0.2462
18						9	9	9	9	0.248505
	13	13								0.2592
			10	11	11					0.2623
						9	9	9	10	0.2631
						9	9	10	10	0.2777
			11	11	11					0.2784
	13	14								0.2800
						9	10	10	10	0.2922
			11	11	12					0.2961
	14	14								0.3037
20						10	10	10	10	0.306796
			11	12	12					0.3137
	14	15				10	10	10	11	0.3229
			12	12	12					0.3313
						10	10	11	11	0.3390

Table 3E-1: Flow area for various nozzle combinations (Continued).

Nozzle Combinations. Sizes in 1/32-in.										Area, in.^{2}
One	Two		Three			Four				
	15	15								0.3451
			12	12	13					0.3505
						10	11	11	11	0.3551
	15	16								0.3689
			12	13	13					0.3697
22						11	11	11	11	0.371223
			13	13	13	11	11	11	12	0.3889
	16	16								0.3927
						11	11	12	12	0.4065
			13	13	14					0.4096
						11	12	12	12	0.4241
			13	14	14					0.4303
24						12	12	12	12	0.441786
	16	18								0.4449
			14	14	14					0.4510
						12	12	12	13	0.4610
			14	14	15					0.4732
						12	12	13	13	0.4801
			14	15	15					0.4955
	18	18								0.4970
						12	13	13	13	0.4993
			15	15	15					0.5177
26						13	13	13	13	0.518486
						13	13	13	14	0.5392
			15	15	16					0.5415
	18	20								0.5553
						13	13	14	14	0.5599
			15	16	16					0.5653
						13	14	14	14	0.5806
			16	16	16					0.5890
28						14	14	14	14	0.601320
	20	20								0.6136
						14	14	14	15	0.6236
			16	16	18					0.6412
						14	14	15	15	0.6458
						14	15	15	15	0.6680
	20	22								0.6780
						15	15	15	15	0.6903
			16	18	18					0.6934
						15	15	15	16	0.7141
						15	15	16	16	0.7378
	22	22								0.7424
			18	18	18					0.7455
						15	16	16	16	0.7616
						16	16	16	16	0.7854
			18	18	20					0.8038
	22	24								0.8130
						16	16	16	18	0.8376
			18	20	20					0.8621
	24	24								0.8836
						16	16	18	18	0.8897
			20	20	20					0.9204

Appendix 3F: Comments

There is a tendency to think of fluids in terms of a static situation as described by Pascal's Principle. Fluid in motion does not have the same pressure throughout the fluid at a specific horizontal datum plane. If it did, a babbling brook could no longer babble. Ripples on a mountain stream would not exist. There would be no rapids with great rough surfaces to thrill those in canoes or rafts in mountain areas. The surfers would disappear from Hawaii's North Shore because there would be no wave action. On the other hand, few would notice because the low pressure zone caused by rapid flow of air across the wing surface would not exist, consequently, no planes would be able to transport surfers to Hawaii anyway. Closer to home, the lack of a change in pressure caused by rapidly flowing fluid would eliminate mud hoppers. (They rely on the Bernoulli principle.)

The extreme complexity of flow patterns in a turbulent fluid is one of the reasons that coefficients are used to approximate pressure losses in flowing fluids. Fluid must have a pressure differential to flow. Each of the curved stream lines in a fluid must be in response to a pressure differential causing the fluid to move in that pattern. Chaotic flow profiles must have a great variety of small pressure differences creating these eddies. The viscosity of the fluid in response to these small pressure differences determines the velocity of the fluid in each of the eddies. Drilling fluid viscosity depends upon the shear rate within the fluid. So a tremendously large matrix of viscosities and flow patterns would be required to accurately describe all of the pressure differentials in a turbulent drilling fluid.

3F.1 Nozzle plugging

Tri-cone bit nozzles can be varied in diameter to enhance the cross-flow beneath the bit. If one nozzle is made smaller or larger than the other two, drilling fluid will tend to sweep under two cones more efficiently. The practice of completely plugging one nozzle starves one cone of fluid to keep solids from sticking to the teeth or cone.

PDC bit nozzles should NOT be plugged.

References

1. Ramsey, M. S., Robinson, L. H., Onsite Continuous Hydraulics Optimization (OCHO™), AADE-01-NC-HO-31, AADE 2001 National Drilling Conference, Houston, March 27-29, 2001.
2. Robinson, L.H., "On site nozzle selection increases drilling performance", Petroleum Engineer International, February 1982.
3. Ramsey, M.S., Robinson, L.H., Miller, J.F., Morrison, M.E., "Bottom-hole Pressures Measured While Drilling", IADC/SPE Paper No. 11413, presented at the 1983 IADC/SPE Drilling Conference, New Orleans, Louisiana, Feb 20-23, 1983.
4. Warren, Tommy M., "Evaluation of Jet-Bit Pressure Losses", SPE Drilling Engineering, December, 1989, pp. 335-340.
5. API Recommended Practice (RP) 13D, American Petroleum Institute, 2006 Edition.
6. Ramsey, M.S., Robinson, L.H., "Improved Method of Hydraulic Optimization including Long Bit Runs", AADE-07-NTCE-36, April, 2007.
7. Jet Nozzle Flow Area Calculator located online at www.tdaweb.com/TNFA.calculator.htm
8. Moore, P. L., "Five factors that affect drilling rate," Oil and Gas Journal, October 6, 1958.
9. Robinson, L., Drill Bit Nozzle Pressure Loss [Exploitation of Finagle Factor Technology], AADE-10-DF-HO-2, presented at the AADE Drilling Fluids Conference, Houston, Texas, April 2010.

Chapter 4
Drilling Rate and Mechanical Specific Energy

TABLE OF CONTENTS

4.1 INTRODUCTION

After the best hydraulics are selected using the method presented in Chapter 3, the next step is to utilize the proper flow rate to remove cuttings from beneath the drill bit. If bit teeth regrind cuttings already made, drilling rate will suffer. The bit founder point needs to be determined. The bit founder point is the weight on bit and rotary speed which loads the bit so much that the drilling fluid ceases to remove all of the cuttings from the bottom of the hole.

This chapter is divided into two parts: roller-cone bits and polycrystalline diamond compact (PDC) bits. These bits drill rock with different mechanisms. Roller-cone bit teeth compress the rock and break it by exceeding the compressive strength of the rock. PDC bits break the rock by scraping or scratching the surface. Rock properties, discussed in the next chapter, will help the understanding of the great difference that these failure modes create for the fastest drilling.

Drilling rate with roller cone bits can be correlated with weight on bit (WOB). Drilling rate with PDC bits correlates with torque not weight on bit. Drilling rate with diamond bits also correlates with torque not weight on the bit. When diamond bits were introduced to the industry, the inability to correlate drilling rate with weight on bit was very obvious. Since PDC bits drill by the same mechanism, the similarity should not be surprising.

With either type of bit, the bit loading must allow all of the cuttings to be removed before they are reground. If cuttings remain on bottom after being created, drilling rate suffers and the bits wear out prematurely.

Drilling rate with roller-cone bits is proportional to the product of the weight on the bit squared $(WOB)^2$ and the rotary speed (N). With PDC and diamond bits, drilling rate is proportional to torque, not weight on bit, and rotary speed.

4.1.1 Roller-cone bits

To find the founder point of a roller-cone bit, high weight on bit is applied to a roller-cone bit and the brake is locked down. The upper end of the drillstring is held in a fixed position. The bit continues to drill and the drillstring stretches until the bit no longer drills. The drillpipe is an elastic body which means that each 2,000-lb load will stretch 1,000 ft of pipe the same amount. As the weight on the bit decreases in increments of 2,000 lb, the drillpipe stretches the same amount for each incremental interval. A drilling rate can now be calculated by measuring the time required for each 2,000-lb decease in bit weight.

The drilling rate can now be plotted as a function of the weight on the bit. This curve is called a “drill-off curve”. The founder point of the bit is the weight on bit which creates more cuttings than the current hydraulics can remove. The drill-off curve is difficult to measure if the filter cake in the well creates too much drag force to prevent the drill collars to apply the bit weight indicated by the weight indicator on the surface. Good drilling practices require eliminating drilled solids from the drilling fluid so that filter cakes are thin and slick.

4.1.2 PDC bits

As discovered when diamond bits were introduced to the drilling industry, drilling rate of a bit that drills by scraping or shearing the rock correlates with torque and not weight on bit. A drill-off curve cannot be produced the same way with a PDC bit as described for a roller-cone bit. When a PDC bit founders, cuttings cling to the bit and “ball the bit”. Roller-cone bits can be cleaned by pumping drilling fluid through the nozzles with the bit off-bottom. This will not remove the cuttings from a PDC bit.

With PDC bits, the evaluation needs to begin with a relatively low weight on bit and slowly increase the bit loading until the founder point is reached. The amount of energy used by the bit is proportional to the product of the torque at the bit (τ) and the rotary speed (RPM). This energy is used to break the rock indicated by the drilling rate. The ratio of the input energy and the drilling rate is constant as more energy is applied to the bit UNTIL the founder point is reached. With a low bit loading (rotary speed and weight on bit), the ratio of the energy input to the drilling rate is determined. As the bit loading is increased, the drilling rate should increase. The ratio will remain constant. After the bit loading (either rotary speed or weight on the bit) reaches the point where all of the cuttings are not being removed from the bottom of the hole, the drilling rate will no longer increase by the same amount and the ratio will increase. This is the founder point.

The torque at the bit should be measured at the bit, but this value is seldom available. Torque is usually measured at the surface and consists of the torque at the bit and the drag torque of the drillstring in the hole. If the filter cake resembles sand paper, the torque at the surface will not always reflect the torque at the bit. A thin, slick filter cake is required to adequately perform this measurement – which means the drilled solids must be removed from the drilling fluid.

Different procedures can be used for roller-cone bits and PDC bits. The traditional “drill-off” test for roller-cone bits requires applying bit weights initially which may founder the bit. The bit is said to be “balled-up” when this occurs. The cuttings may pack so tightly around the bit teeth that they can no longer reach the rock beneath the cuttings bed. Usually, drilling fluid from the nozzles will remove these cuttings from the bit as the bit weight is decreased. A polycrystalline diamond compact (PDC) bit will remain “balled-up” and must

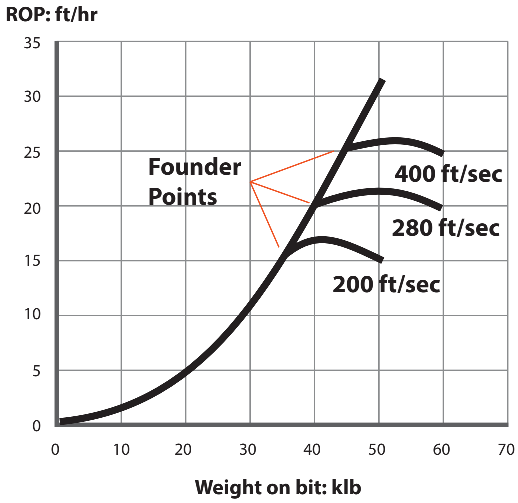


Figure 4-1: Effect of nozzle on founder points.

be removed from the borehole to clean the cuttings from the bit. Obviously, another process must be used to identify the bit founder point. This process is called application of the mechanical specific energy (MSE). The MSE approach may be used for either type of bits and will be discussed first.

4.2 History

The concept of founder points was introduced by Grant Bingham, a drilling engineer with Shell, as far back as the 1950's. A founder point indicates the bit loading that causes chips to form that cannot be removed with the available hydraulics. Obviously increasing the hydraulics (or flow rate for a particular bit) will increase the founder point. Founder points are important for field operations because it defines the point at which increasing bit loading no longer provides the proper increase in drilling rate. The bit then drills at a lower rate of penetration (ROP) than it should. In the worst cases, overloading the bit frequently balls the drill bit and the drill bit quits drilling. In most cases the bits are worn faster than they should be, resulting in bit trips that should not be required. Saving one or more trips out and into a hole makes a large impact on economics.

Rubin Feenstra, Shell, in 1963 (SPE meeting in New Orleans) also published a paper showing how nozzle velocities affected the founder point (Figure 4-1). This curve was obtained by controlling the bottomhole pressure during experiments in the laboratory. In the field, the pressure differential across the bottom of the hole depends upon the flow rate. The pressure drop in the annulus goes up when the flow rate goes up. If the flow rate is decreased, the cuttings in the annulus may accumulate and increase bottomhole pressure because the mud weight in the annulus has increased. Pressure measurements while drilling frequently can indicate poor hole cleaning capabilities. This is particularly true in high angle holes because the effect is immediate. In more vertical holes with slow drilling, the bottomhole pressure may initially decrease when the flow rate decreases; but will probably increase as the cuttings load in the annulus increases.

The curves presented in Figure 4-1 are very important for drillers to understand. These graphs show founder points increasing as the nozzle velocity increases from 200 ft/sec to 400 ft/sec. These changes in nozzle velocities are possible in the field by using the hydraulic optimization procedures described in Chapter 3. Note, however, that if 30,000 lb is applied to the drill bit, no change in drilling rate occurs by using the higher nozzle velocities. If all of the cuttings are being removed from beneath the bit before the next row of teeth reach them, improvements in hydraulics or fluid properties probably will not be reflected in drilling rate. Depending upon the drill bit, the drilling rate after the founder point can decrease significantly, stay about the same, or continue to increase but at a much slower rate. Some bits almost cease drilling when too much weight is applied. Drillers start reporting that the rock has become harder and want to run bits designed to drill harder rocks. In the same formation, bits designed to drill harder rocks will drill much slower than bits designed to drill softer rocks.

4.3 PDC bits

To perform the drill-off tests with roller-cone bits, the maximum weight possible is applied before the brake is locked down. Normally, this will be in a foundered condition. If the maximum weight is applied to a PDC bit, not only will the bit founder but will also ball up with cuttings. A roller-cone bit, if it is not too badly balled up, will clean itself and continue drilling when the weight on the bit is decreased sufficiently. A PDC bit, however, must be pulled from the hole and cleaned. This means that the procedure used to find the founder point of a roller-cone bit cannot be used for a PDC bit.

4.3.1 Mechanical specific energy concept developed

Teale, in a 1960 paper, reported that the energy required to cause failure of rocks in a tunneling process is related to the compressive strength of the rock. This is quite obvious since the compressive strength stress is the amount of energy to cause failure per unit volume.

"In rotary non-percussive drilling, work is done both by the thrust, F, lb, and the torque, T, lb in. If the rotation speed is N (rev/min), the area of the hole or excavation A (in.^{2}) and the penetration rate u (in./min), the total work done in one minute is $Fu + \pi NT$ (in. lb). The volume of rock excavated in one minute is (Au) (in.^{3})."

Designating "e" as the specific energy and dividing work by volume gives:

Table 4-1: Effect of pore fluid in yield strength of limestone.		
Interstitial Fluid	Acid Form	Yield Strength: 1000 psi
Sodium Adipate	COOH (CH_2)$_4$ COOH	16.9
Water	H_2O	16.0
Sodium Hydroxide	-	14.2
Sodium Azelate	COOH (CH_2)$_7$ COOH	13.0
Sodium Citrate	$COOHCH_2C(OH)COOH\ CH_2COOH$	12.0

$$e = \left(\frac{F}{A}\right) + \left(\frac{2\pi}{A}\right)\left(\frac{NT}{u}\right)$$

Equation 4-1

Using subscripts "t" and "r" to denote the thrust and rotary components of the specific energy "e":

$$e_r = \left(\frac{F}{A}\right) \text{ in. lb/in.}^3$$

Equation 4-2

$$e_t = \left(\frac{2\pi}{A}\right)\left(\frac{NT}{u}\right) \text{ in. lb/in.}^3$$

Equation 4-3

The thrust component, (F/A), is equivalent to the mean pressure exerted by the thrust over the cross-sectional area of the hole. Specific energy is, in fact dimensionally identical with pressure or stress, since (lb in./in.^{3}) is equivalent to (lb/in.^{2}).

Physically this arises from the fact that if a force F acting on and normal to a surface area A moves it through a distance ds, the increment of work done, dW, is equal to Fds. Pressure (or stress) is defined fundamentally as energy (or work) per unit volume.

Pressure or stress is fundamentally defined as energy per unit volume.

Another interesting item in the Teale paper was the fact that the specific energy data while drilling with a Hughes W7R bit seemed to correlate with the compressive strength and the Security M3 bit did not. The W7R bit was a very short tooth, roller-cone bit that drilled primarily by crushing the rock. The Security M3 milled tooth bit was designed to scoop (or as Teale says have "greater scuffing action") and was designed for much softer rocks. In today's IADC bit code notation, the W7R bit would probably be classified as an IADC code 341 and the M3 as a 121 or a 111. Drill bits at that time used roller bearings, which were not sealed. Tungsten carbide bits were not available.

Pressure and normal stress by definition are energy/volume. Teale related his mining progress to the compressive strength of the rock. This was not applied to oil well drilling when it was first published because the compressive strength of rocks at the bottom of a well is completely different (higher) than the compressive strength of the rock at the surface. Pressure makes a significant change in both the strength of the rock and the mode of failure. At the surface most rocks fail brittlely; and with differential pressure, rocks become very malleable. Also, PDC bits fail the rock by a scraping action and not by compression. The strength of the rock in that mode of failure is significantly different from the strength of the rock in compression. In the 1950s and 1960s, diamond bits also were used and it was quickly observed that drilling rates could not be correlated with weight on the bit but was correlated to the torque applied to the bit. Since PDC bits drill by the same failure mechanism as diamond bits, PDC drilling rates should correlate better with torque than weight on bit.

Teale's concepts could not be used to calculate drilling rates and the amount of energy that was consumed to make the rock fail could also not be related to the unconfined compressive strength of the rock. However, the mathematical relationship should be the same under downhole pressure conditions as it is at atmospheric pressure. This was verified by Pessier.

Some interesting drilling data was published many years ago about hardness reducers (SPE 1709). (From the SPE number, it is obvious that this is old data.). Indiana Limestone cylinders were compressed to failure while applying 10,000-psi confining pressure and 5,000-psi pore pressure. In this case with water as a pore fluid, the failure mechanism is malleable at a strength of about 14,000 psi. When adipic acid (COOH(CH_2)$_4$ COOH) was neutralized with sodium hydroxide to a pH of 10, the strength of Indiana limestone increased from 16,000 psi to about 16,900 psi. When azelaic acid (COOH(CH_2)$_7$ COOH) was neutralized

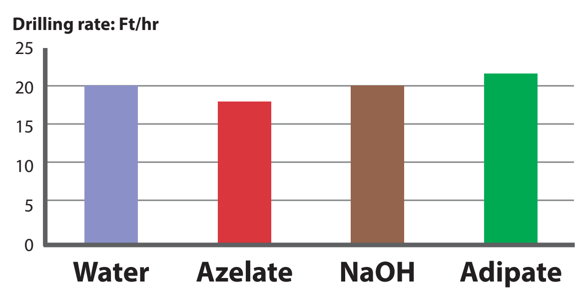


Figure 4-2: Effect of chemicals on roller-cone ROP.

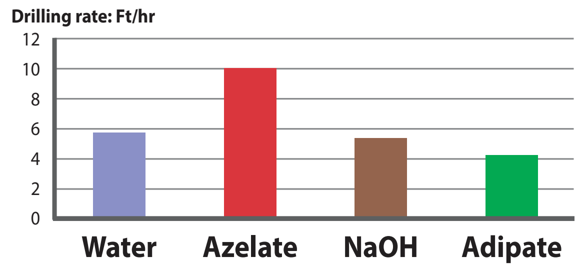


Figure 4-3: Effect of chemicals on roller cone ROP.

with sodium hydroxide, pH 10, and used as the pore fluid, the strength of Indiana limestone, under the same pressure conditions, decreased to 13,000 psi. If the pore pressure and the confining pressures were the same, the pore fluid had very little effect on the 8,000-psi strength of the brittle rock.

The drilling rates, however, were surprising. A 1¼ in. microbit was used to drill four inch cubes of Indiana limestone with the solutions just described. With a borehole pressure of 2,000 psi and no pore pressure, the sodium adipate drilled faster than the sodium azelate solution (Figure 4-2). The sodium azelate drilling fluid had a slower drilling rate, contrary to intuitive reasoning.

The mystery was resolved by repeating the tests and using a bladed drag bit. In this case the rock softener drilled faster than the rock hardener (Figure 4-3). The dicarboxcylic salts changed the mode of failure. The sodium adipate increased the rock strength but caused the rock to fail in a more brittle manner. The sodium azelate decreased the rock strength but caused the rock to fail more malleably. The scraping mode of failure with the drag blade is exactly the same mode of failure achieved with PDC bits.

4.4 Application of mechanical specific energy concept for PDC drilling

The mechanical specific energy concept produces a good guideline for improving drill bit performance, but the quantity of energy needed to cause rock failure is probably not known. This stymied earlier research on the application of this concept and theory to drag bit or PDC drilling. What is observed, however, is a measurement proportional to the utilization of the energy supplied at the bit. This gives a guideline and a relative basis for comparing good performance with poor application of the energy. If the bit is whirling or vibrating, the torque will change and the penetration rate will change. The relative utilization of energy becomes a great guideline for monitoring the PDC bit performance.

Teale's equation related the energy of drilling rock to the torque and weight applied to a drill bit. Failure stress of a rock is the amount of energy per unit volume of rock required to make the rock fail. That is because stress, or pressure, is, by definition, energy per unit volume. The question becomes, how is the strength of a rock determined? Normally, cylinders of rock are compressed and the force per unit area is measured when the rock yields. In brittle failure, the point of failure is quite obvious. In malleable failure, however, the yield point is normally used because the force/deformation relationship does not display a very marked failure point. One major problem with determining failure of cylinders of rock is the problem of the friction force which prevents the top and the bottom of the cylinder from expanding laterally. This creates a large shear force at the intersection of the ends and sides of the cylinder. Normally, the failure plane starts at that junction. The forces preventing movement are so large that the rock grains touching the pistons do not fail. This creates a cone of fracture. In the cone of fracture, the rock grains remain undisturbed and the rock material between these cones is the portion of the cylinder that fails. For brittle failure, this process will give reproducible answers and the values are generally accepted as the compressive strength of the material. In malleable failure, however, where there is no obvious ultimate strength, the actual compressive strength may not be known. The stresses which cause shear failure by dragging diamonds or cutters across the surface are also different from the unconfined compressive strength of rock. This means that the stresses which cause a rock to fail while drilling, particularly with a PDC bit, may not be directly related to the rock strength. The rocks also are much stronger when there is a differential pressure than they are when the pore and confining pressures are the same. As

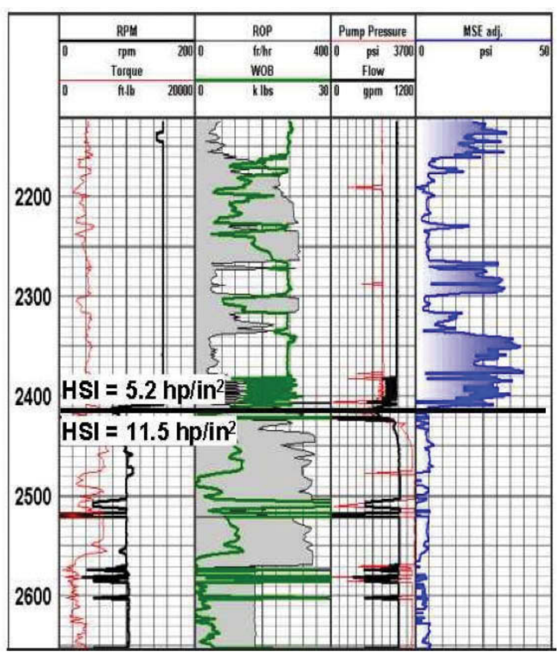


Figure 4-4: The founder point of the bit was raised by decreasing the nozzle size to increase the HSI. SPE/IADC 92194.

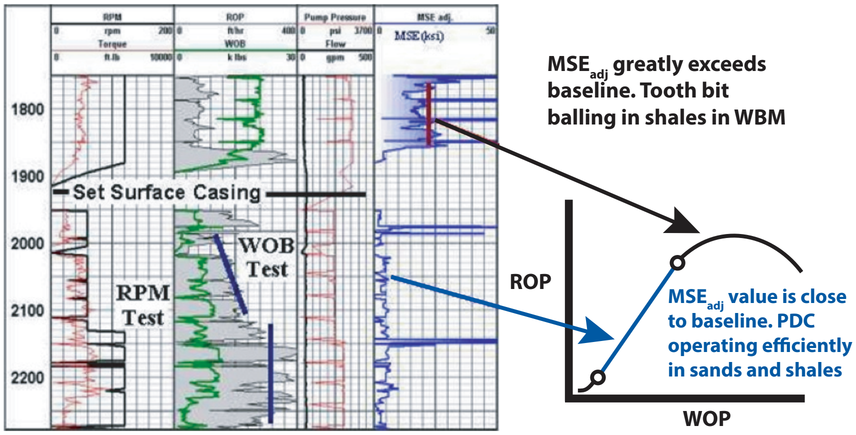


Figure 4-5: WOB and RPM tests are conducted by observing the MSE while increasing parameters. If the MSE remains close to the baseline value while raising WOB, the bit is as efficient at the high load as before. ROP will continue to increase linearly with WOB. SPE/IADC 92194.

rock fails — as any granular material fails, the pore space increases. This means at the bottom of a borehole, shales may exhibit a radically different failure process than will be observed at atmospheric conditions. As the pore pressure decreases (from an increase in pore space), the material fails more malleably and is stronger. Drag blade cutters respond better to this type of failure than do compressive-tooth-type failures. The transition from brittle to malleable failure could cause PDC bits to drill faster with a high differential pressure. With a roller-cone bits, drilling rate will decrease when the pressure differential increases.

All these concepts are based on the fact that the drilling is performed with bit loads below the founder point of the bit. Hydraulics should be examined and nozzles changed to provide either the maximum hydraulic impact or the maximum hydraulic power of the fluid striking the bottom of the hole. Conventional wisdom is that PDC hydraulics should be based on hydraulic power – usually expressed as horsepower per square inch of bit diameter (HSI). Hydraulics for roller-cone bits commonly is based on hydraulic impact. Data to support these assumptions seems difficult to locate. Side-by-side comparisons where all variables have been carefully monitored seems to be lacking in the literature.

The actual strength of the material drilled downhole is unknown. This is discussed in the chapter on rock failure. The trends, however, should be and are very easily observed. When an excessive amount of energy is being used to drill compared to that which would only be necessary to make the rock fail, the PDC bit is floundering. Monitoring the energy supplied to the PDC bit was a brilliant concept initiated by F. Dupriest in 2006. While the absolute numbers may not be known, the relative values reveal much about the drilling mechanism and the utilization of the energy, or power, supplied to the bit.

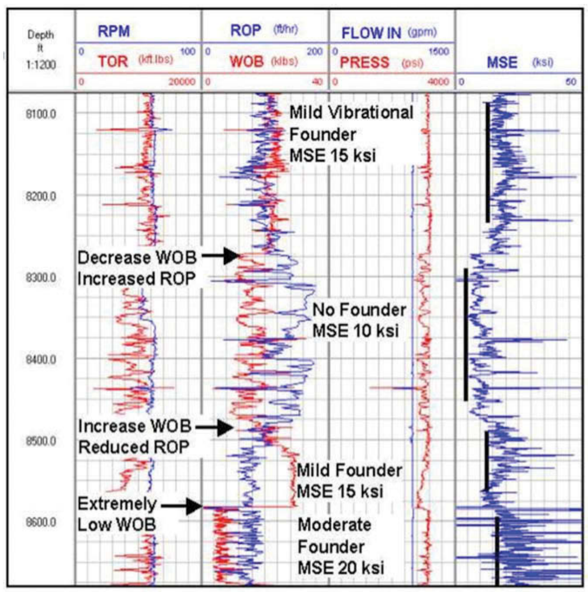


Figure 4-6: Initial MSE$_{adj}$ suggested mild vibrational founder. System became more efficient at reduced WOB. Energy loss returned with the weight was raised back. A final test at very low weight showed even greater inefficiency, possibly due to increased whirl or low depth of cut. SPE/IADC 92194.

4.5 Applying the mechanical specific energy (MSE) concept

Real-time MSE surveillance on drilling rigs has been reported by Dupriest, et al. They developed a software package to provide real-time display of mechanical specific energy based on surface measurements. It is used to find the founder point for PDC bits, and in some cases the cause of the founder. Mechanical specific energy is a ratio. It quantifies the relationship between input energy and ROP. This ratio should be constant for a given rock, which is to say that a given volume of rock requires a given amount of energy to destroy. The relationship between energy and ROP that they used were:

$$MSE \approx \text{Input Energy} / \text{Output ROP} \qquad \textbf{Equation 4-5}$$

$$MSE = [480 \times Tor \times RPM / (Dia^2 \times ROP)] + [4 \times WOB / Dia^2 \times \pi] \qquad \textbf{Equation 4-6}$$

For roller-cone drill bits, the rate of penetration (ROP), or drilling rate, increases as a square of the weight on the bit up to the founder point. In general, the torque generated by a roller-cone bit is proportional to the weight on the bit at any specific rotary speed. The founder point indicates the drill bit is re-drilling cuttings that should have been removed from the bottom of the hole. At this point, energy applied to the bit does not result in the same transfer of energy to creating more cuttings. With a PDC bit, the failure mechanism is different from the roller-cone bit and is more like a diamond bit. For PDC and diamond bits, drilling rate correlates with the torque on the bit instead of the weight on the bit. Founder points still occur but there are also more reasons and physical events that prevent the efficient application of energy from the bit to remove rock. While drilling efficiently, the mechanical specific energy should be constant. When the bit is foundering, the same amount of energy will not result in the same drilling rate. As a diagnostic tool, the measurement of the MSE and the ROP provides an indicator of the drilling efficiency. Fred Dupriest and William Koedertiz in SPE/IADC 92194 presented illustrations of how these measurements could be used to improve drilling rates with PDC bits. Figures 4-5 and 4-6 are reproduced from their paper .

This increased the drilling rate in a water-based drilling fluid to above 350 ft/hr.

4.5.1 MSE application to roller-cone bits

Mechanical specific energy concepts haves been developed also for roller-cone bits as well as PDC bits. Caicedo, et al, report using the concept for roller-cone bits.

Frequently, the question is asked: "Does anyone actually perform drill-off tests for roller-cone bits?" The answer is "not usually". Perhaps, even though the technology is well proven, the manual labor involved prevents most operators or drillers from actually performing these tests. The concept is still included in courses which include drilling performance because it describes many events which need explanation in the field. The method works and can improve performance significantly. Many drillers actually attempt to find the "sweet spot" in their search for the founder point. They adjust the weight on bit and the rotary speed to find the fastest drilling rate possible for the hydraulics available. This is an empirical approach to finding the founder point of the bit.

One service company devised an automatic system that recorded the decrease in bit weight (or, more specifically, the increase in hookload) as a function of time. The problem was that the recorder was making measurements during a very short time period. If the weight changes are somewhat erratic, the drill-off curves are incomprehensible. Drillers do not like to use equipment which only works about half the time. One of the times, when good drill-off curves were being displayed, the drillers found that they were applying too much weight to the 7 ⅞-in. bit. In an old field that had over 2,000 wells, the Authorization for Expenditure (AFE) was well established, as were the drilling procedures. The eagerness to drill as fast as possible resulted in the bit drilling in a foundered condition. Decreasing the WOB almost doubled the drilling rate and allowed the bits to drill about three times longer. This saved about 30% of the AFE.

4.6 Comment

Failure stress and pressure are defined as energy per unit volume. The energy causing a rock to fail is called the rock strength. Rock can fail in compression or in a shear mode when cut by a blade dragging across the face of the rock. In all cases, however, the failure is caused by exceeding the energy per unit volume. The mechanical specific energy (MSE), as used for PDC bits considers the amount of energy used to destroy the rock relative to the rate of penetration. A bit can be 100% efficient but not drilling as fast as possible. More weight can be applied to the bit, or the rotary speed increased, and the MSE could be the same low value. The rate of penetration could increase until a flounder point is reached. The flounder could be caused by failure to remove cuttings or vibration at the bit. In either case, the best performance of a PDC bit can be achieved by maintaining a low MSE while increasing the penetration rate until just before the flounder point.

As the MSE concept is explored further, some surprising results have been observed. For years, the quest of many researchers has been to measure vibration and high frequency information at the bit. Both Exxon and Shell research worked for many years during the 1970s trying to install a wire line in the drillpipe to permit measurements of these vibrations. In the early 1960's, Jersey Production Research installed a tape recorder in the BHA just above a milled-tooth, roller-cone bit. They were able to record a few seconds of information. Many of the resonance nodes could be recognized, but there were a couple of frequencies which did not seem to relate to anything. Now, even though these frequencies and vibrations have not been measured, their presence is obvious from measurements of mechanical energy.

Fred Dupriest has explored these effects and reports: "You might be amazed at what we're doing with vibrations. Five years ago none of us were even worried about it, and now

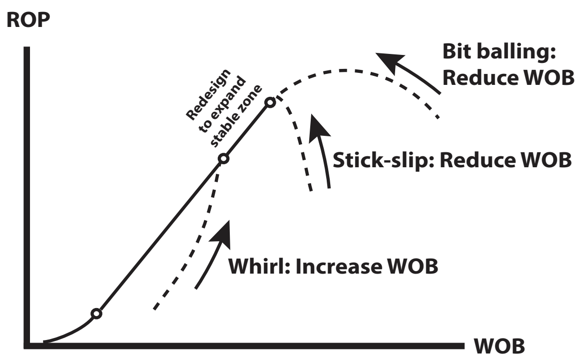


Figure 4-7: Bit whirl and stick-slip vibration may also create a founder point.

we understand it's by far the dominant bit limiter in all of our operations (bit balling is dead). We're drilling 500 ft/hr in South Texas with water-based mud (WBM) and no balling with HSIs of 9 to 11 horsepower per square inch of bit diameter. The performance in about 30-40% of our worldwide footage is affected by some level of whirl. Almost all of the rest is controlled by non-bit limiters like hole cleaning and shaker capacity. Whirl and hole cleaning rates are the ballgame and the current performance frontier for us. We've also become sensitized to the borehole patterns whirl creates and the impact on our operations ($4 million/well in Sakhalin) and now understand that much of all the "tight hole" we've always seen on trips has been due to whirl-induced patterns (not swelling shales). Virtually all of our logging while drilling (LWD) damage and bit wear is also due to vibrations. We don't tend to wear out bits as much as vibrate them to death and this is very clear now that we've changed our grading practices to include digital photos. We've extended bit runs by as much as 4x in places like Sable Island by intensely managing whirl with MSE and downhole tools. In EG , we were tripping an average of one time in every hole interval for LWD failure, and after rollout of the Fast Drilling Process, they went 5 months without a failure. We're getting runs of 7-10 days in Sakhalin without an LWD failure, and making 23,000 ft of 80 degree hole with one bit and no wiper trips. It's all about whirl management. MSE really talks to you when you have whirl, and for the last 2 years we've gotten much more intense about both real time management of it with WOB and RPM and redesign of bottomhole assemblies (BHAs)…. But altogether we're still on a steep performance and learning curve.

"The other vibrational limiter is stick slip. We essentially reduce whirl in real time by raising WOB. This works until the system gets enough torque in it to initiate stick slip. That's the old sweet spot. In the FDP workflow, the engineer then goes to work on redesign to extend the onset of stick-slip. I use the attached (Figure 4-7) to explain it in the old drill off test terms, which is exactly what you described seeing in the field. This plot doesn't show RPM, but we also run speed tests and use MSE to find the RPMs at which we are quiet. In the end you want the highest combination of RPM and WOB with the lowest MSE. Anytime we're not on the straight line, MSE talks to us. So we can see when we're in whirl or stick-slip.

"We're also raising another generation of drillers who think that knowing all of this is normal, that all drillers should know how to manage whirl, and that engineers should know how to redesign the systems. The industry is a bit behind in terms of operationalizing this knowledge, but we're all headed in the same direction."

4.7 Vibrations

When performing a drill-off test with a roller-cone bit, the weight indicator hand normally smoothly increases as the weight on the drill bit decreases. Usually, at some weight on the bit, the weight indicator hand will start oscillating back and forth. Getting a good reading for calculation of rate of penetration will not be possible for this interval. The oscillations occur because the drillstring has started resonating. Good drillers automatically avoid these vibrations. They vary with rotary speed and are unique for the drillstring in the hole. Usually, the vibration is so small — AT THE SURFACE — that it is not noticeable. These vibrations at the bottom of the hole can destroy a drill bit.

When the torque and drilling rate are varying, or oscillating, the drillstring is probably experiencing stick-slip. Stick-slip causes the drillstring to cease turning in the worst cases and slow down because of more drag on the pipe. The solution is to decrease the weight on the bit and increase the rotary speed.

When the torque increases significantly and the drilling rate decreases the drill bit is whirling on bottom. Bit whirl can seriously damage the drill bit. In the worse cases, the entire rig can be vibrating. The solution is to pick up off bottom and stop the pipe rotation. The bit should then be lowered back to bottom with a higher weight on bit and the rotation speed decreased. This is what is done with a hand drill when drilling a large diameter hole. As the hand drill starts vibrating, the rotation speed is decreased and the bit is pushed harder into the material.

4.8 Roller-cone bits

Drilling rates for roller-cone bits may be calculated from Equation 4-7:

$$ROP = \frac{K\left(\frac{W}{D}\right)^2 N^{\lambda}}{m + \Delta P} \qquad \textbf{Equation 4-7}$$

Where:

K is the rock drillability
W is the weight on bit
D is the bit diameter
N is the rotary speed
□ is an exponent (around 0.8)
Δ P is the differential pressure
m is a constant (a value close to the rock tensile strength).

Equation 4-7 can be used for bit loadings (weight on bit and rotary speeds) up to the point at which the bit founders. A bit founders when the teeth start breaking rock that was already broken. After the founder point, drilling rates may increase slightly with more bit loading, stay the same, or decrease with more bit loading. In the extreme cases, drilling rates may be one-third of the drilling rate at the founder point. This makes the rock look "hard" and may influence the choice of bits used in the hole.

4.9 How to perform drill-off tests with roller-cone bits

4.9 .1 Procedure for roller-cone bits

- Select a rotary speed and a maximum weight to be applied to the bit. The maximum weight may be determined from the drill collars in the hole or the bit manufacturer's recommendations.
- Set the rotary speed, and apply the maximum weight. Drill a short distance and recheck the rotary speed.
- Lock the brake down and record the time.
- Record the time for every 2,000 lb increase in string weight (or decrease in bit weight).
- Continue the procedure until about 25% of the original bit weight remains. Continuing to
- If significant discontinuities are observed in the data, the formation may have changed and the test needs to be repeated – particularly in the higher bit weight range.
- Calculate rate of penetration (ROP) for each change in bit weight from Equation 4-8:

$$ROP = \frac{\dfrac{(SC)(DP\ length)(\Delta WOB)}{(10{,}000\ ft)\ (1{,}000\ lb)} \left[\dfrac{3{,}600\ sec}{hr}\right]\left[\dfrac{ft}{12\ in.}\right]}{\Delta T}$$

Equation 4-8

Where:

SC is the stretch constant
DP length is the drillpipe length
WOB is Δp_{change} in bit weight for each interval
ΔT is the time, in seconds, the change bit weight

- Plot the drill-off curve.

These calculations may be easily performed on a spread sheet like Excel or Lotus. Note the numerator of Equation 4-8 is a constant for the tests. Almost any "constant" could be used to obtain the shape of the curve and locate the founder point. In that case, the prediction of drilling rate would not be possible.

4.9.2 Discussion

Founder points for roller-cone bits may be found at the drill site using drill-off tests. Many dedicated drillers frequently seek the "sweet spot" as they search for faster drilling rates. They change the rotary speed and weight on bit until they think they achieve the best possible drilling rate. In 1958, Arthur Lubinski suggested a method of timing how long it took the bit weight to drill-off as a method to find the sweet spot or the founder point.

With the brake locked in place, the top part of the drillstring does not move. As the bit makes hole, the drillpipe stretches. Every decrease of a 2,000-lb bit weight will increase the drillstring length the same amount because the pipe is elastic. (See Appendix 4B.) Generally, the drill collars are so large that they do not stretch as much as the drillpipe and can be neglected in the calculations. The amount of stretch can be approximated by the stretch constants available for stuck pipe calculations or it can be measured on the rig floor. Stop the rotary and mark the drillstring. Apply 10,000 lb to the bit and measure the movement; apply another 10,000-lb bit weight and measure again. Average these two numbers to identify the elastic constant of the drillstring.

These calculations may be easily performed on an Excel spread sheet. Note the numerator of Equation 4-8 is a constant for the tests. Almost any value can be used as the constant to provide the founder point weight. The value calculated for drilling rate will be in error, but the shape of the curve will identify the bit weight which causes the bit to founder.

4.9.3 Test data

Drill-off Test K at 14,500 ft indicated a founder point around a 37,000-lb bit weight. The triangle data point was used to calculate the solid curve shown in Figure 4-8. This data indicates that the hydraulics were insufficient for the drill bit.

Unfortunately, not all data is as easy to interpret as Drill-off Test K. In many holes the stick-slip of the drill collars prevents the weight indicator from actually following the weight on the bit. This problem has led to the abandonment of this method many years ago because of the erratic results. Some of the data looks like the data presented in Figure 4-9 from Test A20.

Joining all of these data creates an almost incomprehensible maze. This is the reason the method was abandoned many years ago. In an attempt to determine the founder point in at the rig site, many other techniques were tried. The most popular was measuring the time required to drill 3 ft at different WOB and RPM. This gave accurate information, but by the time all of the bit weights and rotary speeds were tested, the bit was dull. Selecting only five or six different combinations of WOB and RPM failed to produce a sufficient indicator of the founder point. A variety of other techniques was tried, including measuring from squeak to squeak on the brake to stripping the drilling recorder line to the top of the traveling block . Finally, the erratic data was examined again.

Buried within the data in Figure 4-9, however, is the founder point. The data points to the right of a 10,000-lb bit weight seem to group into some type of relatively constant value. If the reason for the irregularity is stick-slip, perhaps the time intervals for measurements are too short. This data could be analyzed by assuming that the bit weight change was 4,000 lb or 6,000 lb between data points. Assuming a 6,000 lb change in bit weight, ROP is calculated for the change in bit weight from 50,000 lb to 48,000 lb and then from 48,000 lb to 42,000 lb. In this way no data is discarded, but, in Figure 4-10, the data is smoothed into something comprehensible.

Since the ROP is a function of the weight on bit squared, a theoretical curve was plotted using one data point in Figure 4-11 to plot the drilling rate with the squared relationship of the weight on bit.

The data seems "well-behaved" between 21,000 lb and 13,000 lb, so the drilling rate at 21,000 lb was used to calculate a constant of proportionality. In Figure 4-11, the curve without data points represents the theoretical curve. Now the irregular data seems to indicate a founder point in the range of a 35,000-lb bit weight. This was confirmed at the rig by comparing the drilling rate at that bit weight with the drilling rate at 45,000 lb.

Generally, most data can be smoothed by just using a change of a 4,000-lb bit weight instead of 6,000 lb. The example in Figure 4-10 was the worst set of data taken in the field. By using the moving average smoothing technique, even that data could be interpreted.

4.10 Indications of tooth failure

Early in the development of this smoothing technique, data was acquired to validate the fact that rate of penetration was a function of the square of the weight on the bit. This required the drill-off tests to extend into the very low weight-on-bit range. Several field tests confirmed that relationship. During one of these attempts very early in the development of the technique, however, some unusual drill-off data was recorded. This data seemed to indicate that the proposed technique

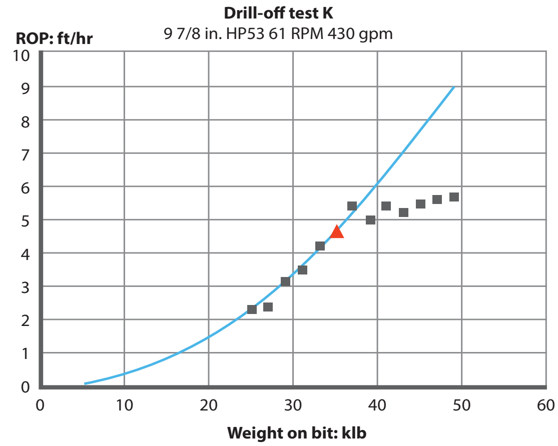


Figure 4-8: Rig site drill-off test.

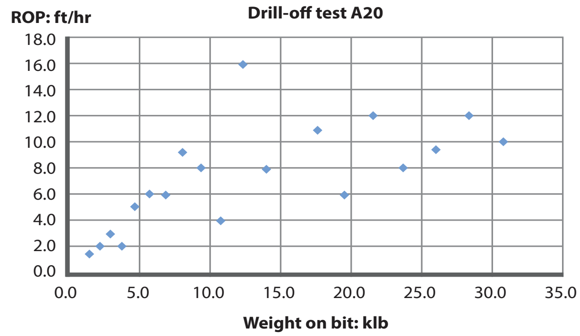


Figure 4-9: Typical data from a poor quality wellbore.

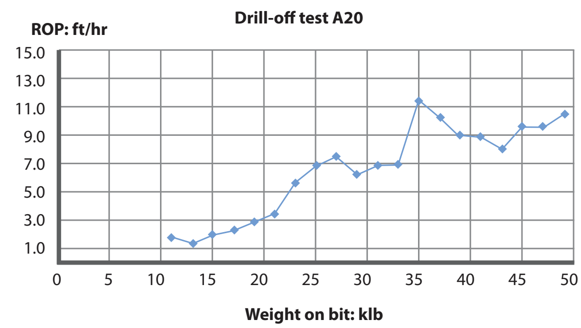


Figure 4-10: Smoothing drill-off data.

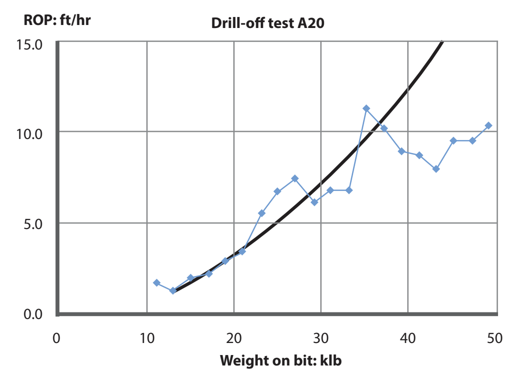


Figure 4-11: Comparing drill-off data to a theoretical curve.

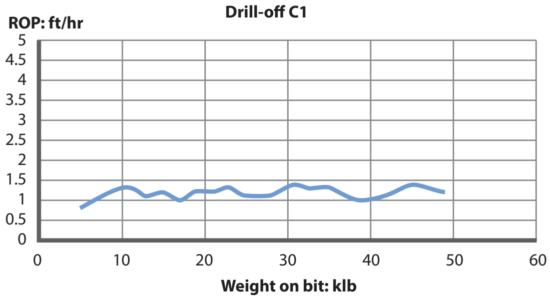


Figure 4-12: Strange drill-off data.

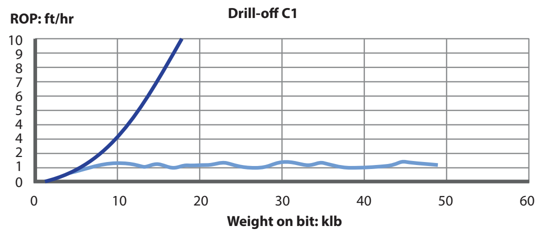


Figure 4-13: Comparing theoretical curve with dull bit drill-off data. Graph shows a J22 bit at 15,100 ft at 60 rpm in a 17.0-ppg drilling fluid.

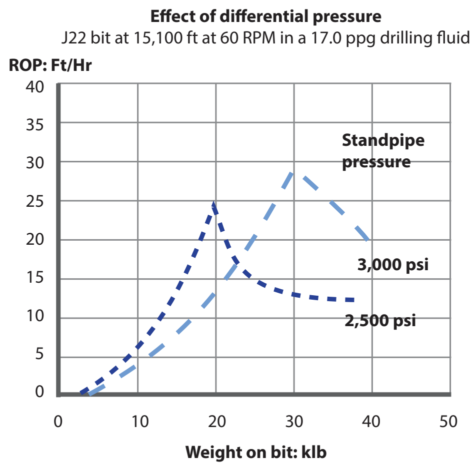


Figure 4-14: Field measurements of the effect of equivalent circulating density.

was invalid. The drill-off test data, Figure 4-12, indicated that the drilling rate was independent of weight on bit.

The rig supervisor indicated that the bit would be pulled the next morning because of a low penetration rate. After this drill-off test, the entire project seemed in jeopardy. Clearly, ROP was not a function of weight-on-bit squared. When the bit arrived at the surface, the reason became completely clear. The IADC 537 bit had only a few shards of inserts left on the cones. The bit foundered within the first 5,000-lb bit weight. The bit should have been pulled long before the drill-off test was conducted.

Assuming that the final point on the drill-off curve was the founder point, the drilling rate with 10,000-lb bit weight should have been 10 times the measured value (Figure 4-13).

Later, a similar set of data was observed from a small drilling rig equipped with small duplex pumps. Insufficient hydraulics can also result in low founder points. Regardless of the hydraulics available at a rig, the founder point determination can guide the way to cheaper drilling.

4.11 Effect of decreasing standpipe pressure

In a vertical well, the standpipe pressure was decreased from 3,000 psi to 2,500 psi and another drill-off test performed (Figure 4-14). The equivalent circulating pressure was very close to the formation pressure. The decrease in bottomhole cleaning should decrease the founder point. It did, however, the drilling rate below the founder point was higher for the lower standpipe pressure. With a 17,000-lb bit weight, decreasing the standpipe pressure increased the drilling rate from 9.8 ft/hr to 18 ft/hr. Past the founder points, however, at a 40,000-lb bit weight, the rate of penetration was higher for the higher standpipe pressure (12 ft/hr compared to 20 ft/hr). Observe also that if the hydraulics were optimized and improved, this bit could have drilled significantly faster with a 30,000 lb bit weight. Calculating the projected drilling rate from the drill-off tests, at a 40,000-lb bit weight with adequate or better hydraulics, this bit should have been drilling at almost 100 ft/hr. With the hydraulics actually available, increasing the bit weight to 40,000 lb decreased the drilling rate. The rig was drilling with a 40,000 lb bit weight before these drill-off tests were performed.

4.12 Comment about "recommended" bit weights

Bit manufacturers have guidelines for maximum weight which should be applied to roller-cone bits for certain rotary speeds. In the drilling situation shown in Figure 4-14, the guidelines would have suggested that as much as 50,000 lb could be applied to the bit. Clearly, this would not be possible with the rig hydraulics that were available. The bit would be drilling at about one-half the possible drilling rate and wearing out at least twice as fast. Eliminating the excess wear and drilling faster will have a significant effect on the well cost. If one bit trip from a deep well can be eliminated, the cost savings will make a large impact.

4.13 Conclusions

Drill-off data from field tests can be analyzed and bit loading adjusted to prevent bit foundering. This results in drilling rates that are sometimes higher than in the foundered condition; the bits last longer; and fewer bit trips are needed.

Good drilling practices are required before drill-off data can be useful. Specifically, drilled solids must be maintained at very low value to reduce friction drag from poor quality filter cakes, and to decrease the plastic viscosity as low as possible to improve drilled solids removal from the bottom of the hole and transport up the hole.

Appendix 4A: Pipe movement from changes in bit weight

4A.1 Drillpipe stretch while performing drill-off tests

When pipe is struck in a borehole, drillers have found that the approximate depth of the stuck point can be found using the weight indicator and a measuring tape. The stretch of the pipe is proportional to the load applied. Tables are available in many vendor handbooks and the IADC Drilling Manual.

The length change for a 10,000-lb change in hook weight does not need to be very accurate. The actual drilling rate at a constant weight and rotary speed may be slightly different from the value calculated using the slightly inaccurate constant. As long as all drill-off data are compared using the same constant, the founder points and the best operating conditions can be selected from the data.

The change in length (ΔL) of a specific drillpipe string is proportional to the length of the drillpipe (L) and the force applied (F), or:

$\Delta L = S_c \times F \times L$

Where S_c is the constant of proportionality

Some values for this constant of proportionality are presented in Table 4A-1 for a few common drillpipe sizes.

For the drill-off tests, the distance moved per 1,000-lb change in bit weight can be easily calculated. For example, the 5-in. drillpipe at 4,900 ft should have moved 3.7 in. for every 10,000 lb of bit weight applied or removed:

$\Delta L = 3.7$ in.

Use of the stretch-C constant in Table 4A-1 eliminates the need to stop drilling to measure the pipe movement for specific bit weight applications. Obviously, the drill collars will not stretch or compress as much as the drillpipe. The method is only approximate but the constant may be used with confidence to determine founder points, determine drilling rate responses to bit weight and rotary speed and select the best weight/speed values to decrease the cost per foot of hole.

4A.2 Determining stretch

Amount of stretch is determined by using the correct stretch constant from the tables in the following formula:

$\Delta = F \times L \times S_C$

Table 4A-1: Calculation of expected change in drillpipe length as weight is applied to bit.

OD (in.)	Nominal Weight (lb/ft)	ID (in.)	Well Area (sq in.)	Stretch Constant (in./1000 lb/1000 ft)
2-3/8	4.85	1.995	1.304	0.30675
	6.65	1.815	1.843	0.21704
2-7/8	6.85	2.441	1.812	0.22075
	10.40	2.151	2.858	0.13996
3-1/2	9.50	2.992	2.590	0.15444
	13.30	2.764	3.621	0.11047
	15.50	2.602	4.304	0.09294
4	11.85	3.476	3.077	0.13000
	14.00	3.340	3.805	0.10512
4-1/2	13.75	3.958	3.600	0.11111
	16.60	3.826	4.407	0.09076
	18.10	3.754	4.836	0.08271
	20.00	3.640	5.498	0.07275
5	16.25	4.408	4.374	0.09145
	19.50	4.276	5.275	0.07583
5-1/2	21.90	4.778	5.828	0.06863
	24.70	4.670	6.630	0.06033
6-5/8	25.20	5.965	6.526	0.06129

Where:

ΔL = stretch, in.

F = pull force, thousands of lb

L = length, thousands of ft

S_C = charted stretch constant, in. of stretch per thousand lb of pull per thousand ft of length

4A.2.1 Example

Determine the change in pipe length (ΔL) for a 10,000-lb change in bit weight (F) on 15,000 ft (L) of 16.6 lb/ft, 4 ½-in. drillpipe. Use Table 4A-1 to find stretch constant.

$\Delta L = F \times L \times S_C$

$$\Delta L = (10{,}000 \text{ lb})\,(15{,}000 \text{ ft}) \times \left(0.09076 \frac{\text{in.}}{(1{,}000 \text{ lb})(1{,}000 \text{ ft})}\right)$$

$\Delta L = 13.6$ in.

Appendix 4B: How to average time for a 2,000 lb, 4,000 lb and a 6,000 lb change in bit weight

The method of averaging data is presented below in the spread sheet format. Only a segment of the drill off data is presented. The time of day is recorded to the nearest second as the weight indicator hand crosses the indicated weight-on- bit value. Subtracting the time from one weight on bit number to the next value the time required to drill-off 2,000 lb is calculated in seconds. The drilling rate equation using the stretch constant evolves into a constant divided by the time to drill-off the 2,000 lb. In the first chart, the drilling rates are quite variable and would be difficult to interpret.

To account for "stick slip", assume that the time for the bit weight to change by 4,000 lb is used instead of 2,000 lb, but calculate the drilling rate for every 2,000 lb change in bit weight. No data is discarded and this acts like a smoothing function.

In this well, the data was still somewhat confusing, so the average time for a 6,000 lb change in bit weight was needed to analyze the data (Table 4B-3). This helps smooth the data to find the founder point without abandoning any of the information.

Table 4B-1: Sample data sheet.

Weight on Bit, klb	Time of Day	Δ Time, sec	ROP 834/T, ft/hr
42	02:34:35		
		70	11.9
40	02:35:45		
		139	6.0
38	02:38:04		
		76	11.0
36	02:39:20		
		56	14.9
34	02:42:00		
		104	8.0
32	02:42:52		

Table 4B-2: Sample data sheet.

Weight on Bit, klb	Time of Day	2 klb Δ Time, sec	4 klb Δ Time, sec	ROP for 4 klb 1668/T, ft/hr
42	02:34:35			
		70		
40	02:35:45		209	8.0
		139		
38	02:38:04		215	7.8
		76		
36	02:39:20		132	12.6
		56		
34	02:42:00		160	10.4
		104		
32	02:42:52		156	10.7

Table 4B-3: Averaging time over a 6,000 lb change in bit weight.

Weight on Bit, klb	Time of Day	2 klb Δ Time, Sec	6 klb Δ Time, sec	ROP for 6 klb
42	02:34:35			
		70		
40	02:35:45			
		139	285	8.8
38	02:38:04			
		76	271	9.2
36	02:39:20			
		56	236	10.6
34	02:42:00			
		104	212	11.8
32	02:42:52			

References

1. Feenstra, R. and Van Leeuven, J.J.M.: "Full-Scale Experiments on Jets in Impermeable Rock Drilling", JPT (March 1964) pg 329-336.

2. Pessier, Rolf, and Fear, M.J., "Quantifying Common Drilling Problems with Mechanical specific energy and Bit-Specific Coefficient of Sliding Friction", SPE 24584, 1992.

3. Caicedo, H.C., W. M. Calhoun, R.T. Ewy, "Unique ROP Predictor Using Bit-specific Coefficient of Sliding Friction and Mechanical Efficiency as a Function of Confined Compressive Strength Impacts Drilling Performance", SPE/IADC 92576, presented in Amsterdam, The Netherlands, 23-25 February, 2005.

4. Dupriest, F.E. and W.L. Koederitz, "Maximizing Drill Rates with Real-Time Surveillance of Mechanical specific energy", SPE/IADC 92194, presented in Amsterdam, The Netherlands, 23-25 February, 2005.

5. Teale, R. "The Concept of Specific Energy in Rock Drilling", Intl. J. Rock Mech. Mining Sci. (1965) 2, 57-73.

6. Lubinski, A. "Proposal for Future Tests", The Petroleum Engineer, (Jan. 1958).

7. Dupriest, Fred E., Personal Communication, October, 2008.

8. Jorden, J.R. and O.J. Shirley, "Application of Drilling Performance Data to Overpressure Detection", JPT (1966), 1387-1394

9. Bingham, M.G., "A New Approach to Interpreting Rock Drillability", O&G Journal, Nov. 2, 1964 thru April 1965

10. Armenta, Miguel, "Identifying Inefficient Drilling Conditions Using Drilling-Specific Energy, SPE paper 116667, presented 21-24 September 2008 at the SPE Annual Technical Conference, in Denver, CO.

11. Arthur Lubinski. Discussion of Paper by Elmer Decker, H.B, Woods, and D. S. Rowley, "The Effect of Weight and Speed on Penetration. World Oil, Jan, 1958 and Drilling Contractor, August. 1958. Work of an AAODC Committee.

Chapter 5
Factors Affecting Drilling Rate

TABLE OF CONTENTS

5.1 INTRODUCTION

In recent years, PDC bits have become more common in the field. They drill by scraping the rock from the bottom of the hole instead of crushing and gouging as do roller-cone bits. Diamond bits use the same mechanism of rock failure and have been used in very hard rock for many years.

The first drilling was done with cable tools. A chisel would be repeatedly dropped on the bottom of the borehole and break the rock. The chisel would be removed and the broken rock bailed from the bottom of the hole. After the bailer was removed from the hole, the chisel would then be lowered back into the hole and the process repeated.

When rotary drilling initially started, after drilling with cable tools for many years, the initial tendency was to rotate the chisel on bottom. The chisels were made in a shape which resembled a fish tail and were affectionately called "fish tail" bits. The sharp blades would drill shale very rapidly but sandstones would quickly dull the sharp edges. This probably provided the incentive to put some teeth on a cone and roll it around on the bottom of a borehole. Although these new roller-cone bits drilled shale somewhat slower than the chisel, they did not cease drilling in sandstones. They actually drilled sandstone faster than shale even though the shale appears to be a weaker rock.

This chapter is included in this book because it explains the performance of drill bits. Roller-cone bits and PDC bits respond differently to application of bit weight and changes in differential pressure.

5.2 Roller-cone bits

Drilling rates of roller-cone drill bits increase as a square of the weight on the bit until the founder point is reached. As the bit weight is increased above the founder point, the drilling rate can decrease, stay the same, or slowly increase depending upon the bit type and the formation. Drilling with the weight on bit above the founder point should be discouraged. The teeth and the bearings fail much faster resulting in more bit trips.

$$ROP = \frac{K\left(\frac{W}{D}\right)^2 N^{\lambda}}{m + \Delta P} \qquad \textbf{Equation 5-1}$$

Where:

- K is rock drillability
- W is weight on bit
- N is rotary speed
- D is bit diameter
- ΔP is the differential pressure between the bottom of the hole and the formation fluid pressure
- λ and m are constants

5.3 Polycrystalline diamond compact (PDC) bits

Increases in bit weight and rotary speed will increase drilling rates of PDC bits — until the founder point is reached — just as it does with roller-cone bits. However, vibration and bit whirl will also create a faux founder point. There are some significant differences in the effect of the variables which control drilling rates with roller-cone bits (Equation 5-1). When diamond bits were introduced to the drilling industry, engineers quickly found that drilling rate correlated with bit torque and not weight on the bit. Diamond bits drill by shearing the formation rock and not by crushing or impacting the rock. PDC bit performance also depends upon torque at the bit. Torque increases as weight-on-bit is applied but not in the same manner for each bit and each formation. This is the reason that the MSE described in the preceding chapter used torque as the variable instead of weight on bit.

When differential pressure increases at the bottom of a borehole, the rock becomes stronger and more malleable. This is discussed in Section 5.4 of this chapter. PDC bits overcome the strength increase with torque and the malleability increase improves the performance and increases the drilling rate.

A drill bit drills by causing rock to fail. At the surface (under atmospheric pressure) rocks appear hard and brittle. Under controlled conditions of confining and pore pressure, however, the same rock will behave in a totally different manner.

A demonstration of the malleability of Indiana limestone is presented here to illustrate the effect. This limestone is a very uniform, fine grained calcium carbonate which makes it ideal for laboratory testing to obtain reproducibility. A cylinder of the rock was machined to fit into a triaxial compression vessel with "O" rings sealing the lower end of the rock so that pore pressure could be applied to the liquid in the rock. A small ¼-in. wide, ½-in. long metal bar was attached to the piston in a triaxial compression cell. A gel/lignosulfonate drilling fluid was used instead of hydraulic fluid to apply a confining pressure to outside surface of the rock (Figure 5-1).

In the first test, a pressure of 3,000 psi was applied to the drilling fluid surrounding the rock. The pore pressure is open to the atmosphere, so a differential pressure of 3,000 psi exists across the surface of the rock. The simulated bit tooth (a flat metal bar) left a perfect imprint it the top surface of the rock when the piston was pushed into the cell (Figure 5-2). This indicates malleable failure.

With a pore pressure of 3,000 psi and a confining pressure of 3,000 psi, a large cavity was created when the piston was pushed into the upper surface of the rock.

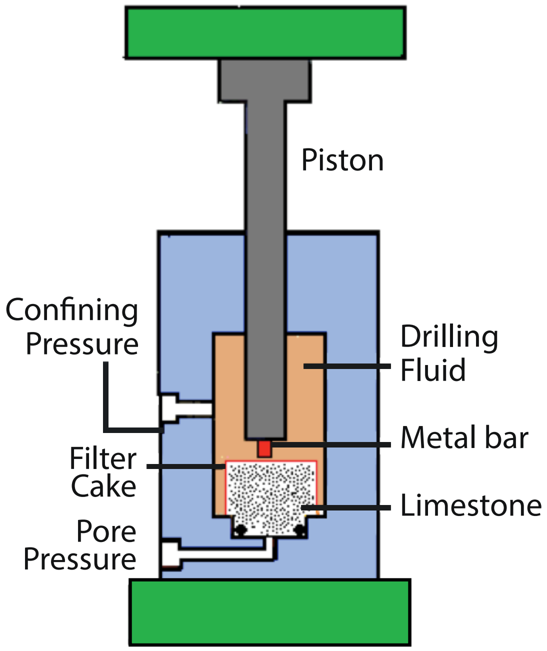


Figure 5-1: Cylinder of rock beneath a simulated bit tooth.

Figure 5-3 shows limestone with 3,000 psi water pressure applied to the top of the rock. The pressure is transmitted into the pore space of the limestone so confining pressures and pore pressures are equal. The failure is brittle.

If this test was performed at atmospheric conditions, the brittle fracturing, would indicate a large failure area (Figure 5-3). This cavity was actually created when the drilling fluid pressure was 3,000 psi and the pore fluid pressure was also 3,000 psi. In both cases, the failure is brittle. With only a 3,000 psi differential pressure, the limestone fails malleably or just as it would if it had been peanut butter.

The plastic nature of the rock is only a downhole condition.

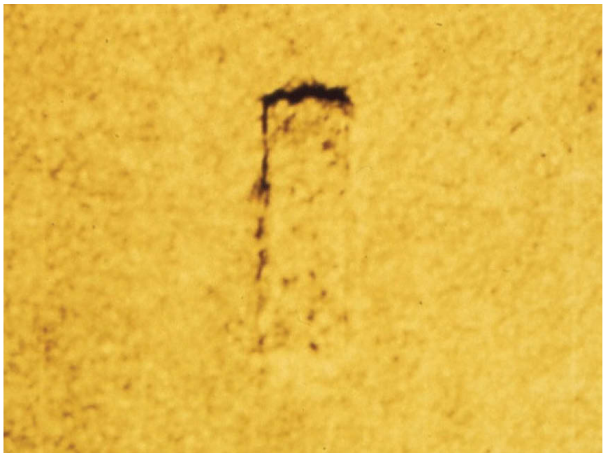


Figure 5-2: A bit tooth only leaves its imprint when Indiana limestone fails malleably.

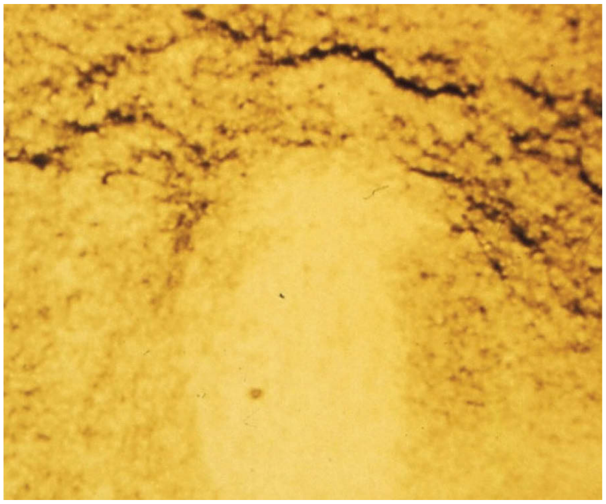


Figure 5-3: Brittle failure removes much more material.

When the chips, cuttings, sloughings, or cores arrive at the surface, the pore pressure and the confining pressures are equalized. The rock becomes brittle. Rock downhole may also retain some of its abrasive characteristics even though it fails in a plastic manner.

5.4 Laboratory examination of rock failure

To examine the pressure effects on rock failure, cylinders of rocks, ¾ in. in diameter and 1 ½ in. long, were jacketed with plastic (Figure 5-4). This separated the internal pore pressure inside of the rock from the confining pressure applied to the cylinder.

The cylinder is placed in a pressure vessel (Figure 5-5). In the pressure vessel, a confining pressure applied to the outside of the plastic jacket and a pore pressure applied to fluid inside the cylinder of rock . The pore pressure is applied to the bottom of the sample. Pressure measurements at the top of the cylinder confirm that the pore pressure is equilibrated completely through the rock.

Three cylinders of Bedford (or Indiana) limestone are shown in Figure 5-6. The rock cylinder on the left exhibits a brittle failure that results at atmospheric conditions or, in this case, when the confining and pore pressures were each 10,000 psi. When the rock fails, a single shear plane traverses the cylinder with a loud noise. The cylinder shown in the middle of the figure is a typical malleable (or ductile, if it was tensile) failure for a rock sample. The pore pressure in this specimen was 5,000 psi and the confining pressure was 10,000 psi.

The force/deformation diagram for Indiana limestone is shown in Figure 5-7.

5.4.1 Failure modes of sedimentary rock

The failure modes and rock behavior under elevated pres-

Figure 5-4: Jacketed sample of rock ready for testing.

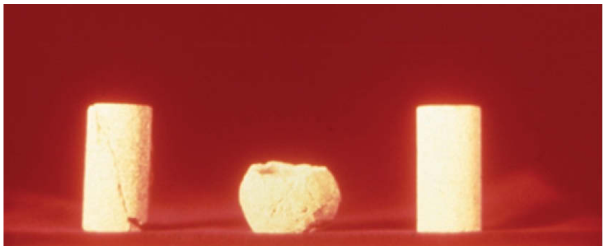


Figure 5-6: Indiana limestone failures.

sures can be described most easily by examining the force/deformation chart as the piston slowly loads the rock cylinder (Figure 5-7).

When the confining and pore pressures were equal at 10,000 psi, the rock fails in a brittle manner. Before failure, however, the force on the top of the cylinder initially deforms the cylinder in an elastic deformation. At a force or load of 2,000 lb, the rock would return to its original length if the load was removed. At a force around 4,000 lb, the force/deformation curve becomes non-linear. At this point the yield strength is reached. Further deformation requires a slight increase in force and then the rock fails in shear. The maximum force is called the point of ultimate strength. When the confining and pore pressures are equal, the magnitude of the pressure has no effect on the ultimate strength. The rock is as strong at 10,000 psi as it is at atmospheric pressure. The failed rock also has the same appearance. A shear plane is created diagonally across the cylinder. The failure plane generally passes between the grains.

As the pore pressure decreases, the rock requires higher loads before failure. In the Indiana limestone when the pore pressure is 8,000 psi with the 10,000 psi confining pressure, the failure profile changes significantly. The ultimate strength and yield strength is higher than before. At the point when the ultimate strength is reached, several shear planes diagonally cross the specimen. The pore space increases dramatically. To maintain a constant 8,000 psi pore pressure, pore fluid must be pumped rapidly into the sample. The shear planes create additional pore space within the sample that causes the pore pressure to diminish.

When the pore pressure is 5,000 psi with the 10,000 psi confining pressure, the force reaches a limit of about 7,000 pounds lb (the ultimate strength). Continual application for this load deforms the rock. This is called a plastic or "malleable" behavior. The rock sample continues to get shorter and remains cohesively coherent after it is removed from the pressure vessel. Again at failure the pore pressure tends to decrease and requires large volumes of pore fluid to maintain pore pressure. This is called a "dilatant" behavior that is common for failure of granular materials (Figure 5-8). This is the reason an almost dry halo surrounds your foot as you walk on the beach near the water line. The foot compresses the sand and the pore space in the sand increases, creating the appearance of less water in the sand surrounding the foot.

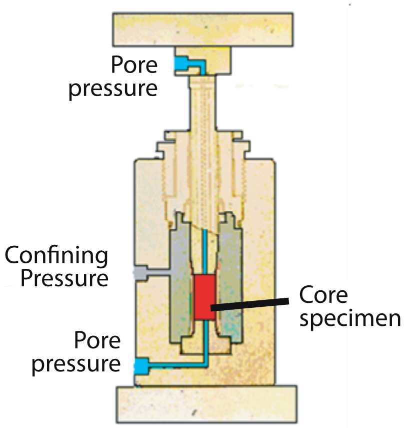


Figure 5-5: Pressure vessel.

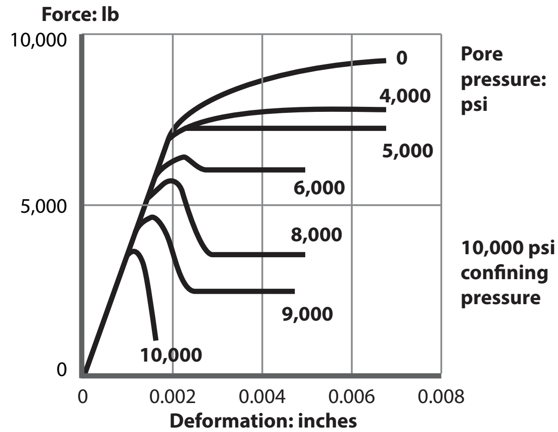


Figure 5-7: Force-deformation diagram for Indiana limestone.

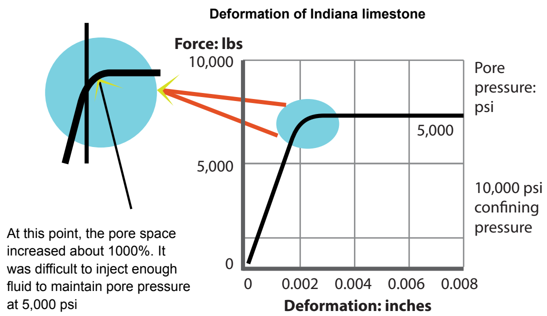


Figure 5-8: Pore volume increases as Indiana limestone starts yielding.

5.4.2 Dilatant failure

The dilatant effect can also be observed with a plastic bottle filled with sand saturated with water. If a small plastic tube is sealed into the top of the bottle and a column of water placed in the tube, the water level will decrease when the sand is squeezed. If there is a small quantity of water above the sand level, the water in the tube will rise when the bottle is squeezed adjacent to the free water.

The increase in strength is caused by the failure planes through the grains and instead of between the grains. The grains are stronger than the bonding material. As the grains are pressed more firmly together (higher differential pressure), failure between the grains is more difficult. This also affects the pressure differential at which the rock starts to assume malleable characteristics.

5.4.3 Failure characteristics of limestone samples

Examining thin sections of the failed Indiana limestone (Figure 5-9) reveals significant twinning of the calcium carbonate crystals when the differential pressure is high. Non-deformed crystals are still present, immediately adjacent to the platens at each end of the core. This called the cone of fracture.

The coefficient of friction between the platen and the end of the cylinder of rock prevents the rock from moving laterally as freely as the center of the cylinder does. Failure occurs between these cones of failure. The deformation of this cylinder forced the two cones of fracture to meet and created the debris in the center of the specimen. The rock outside of the cone of fracture had deformed, twinned, and failed. The rock within the cone of fracture does not fail. This effect creates a very difficult problem when discussing shale properties. Pore pressure measurements are very difficult to make when the cone of fracture has an extremely low permeability, as it would in shale.

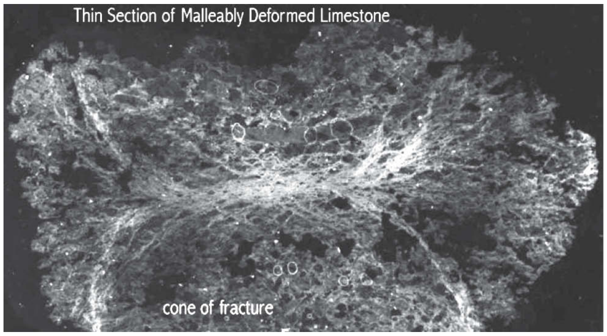


Figure 5-9: Cone of fracture in malleable Indiana limestone.

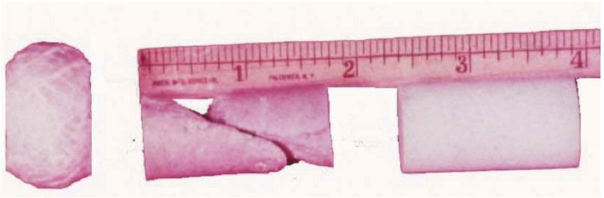


Figure 5-10: Samples of Carthage marble.

Carthage marble (which is a limestone) exhibits both malleable and brittle failure. A cylinder before compression is shown on the right. The brittle failure of the specimen in the center of Figure 5-10 occurs when the rock is compressed with the piston when the pore and confining pressures are equal. The sample on the left is a typical failed sample when the pore pressure is much lower than the confining pressure.

Sandstones behave in a similar manner to limestones except that the transition from brittle to malleable failure requires a much higher pressure differential. This should be anticipated because the quartz grains are much stronger than the calcium carbonate grains in the limestone.

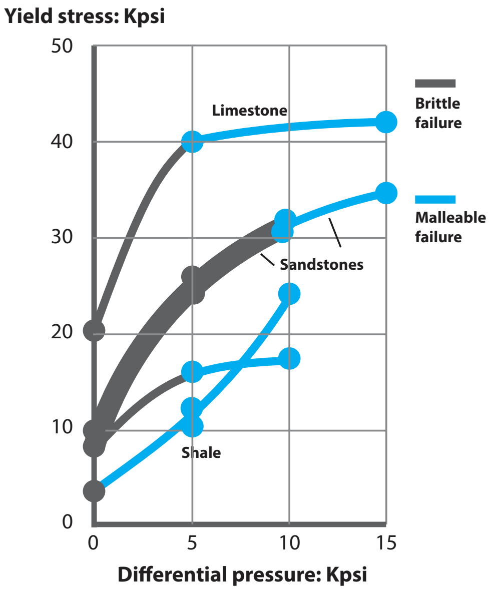


Figure 5-11: Yield stress of several different rocks.

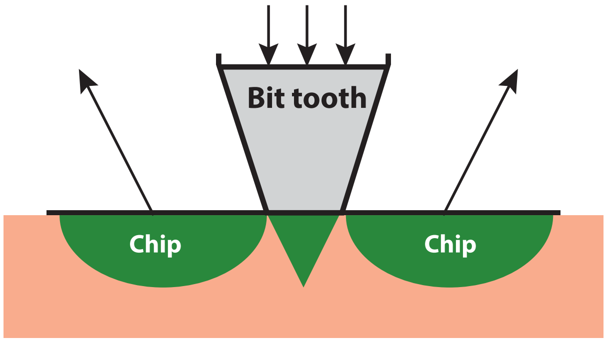


Figure 5-12: Bit tooth impacting rock.

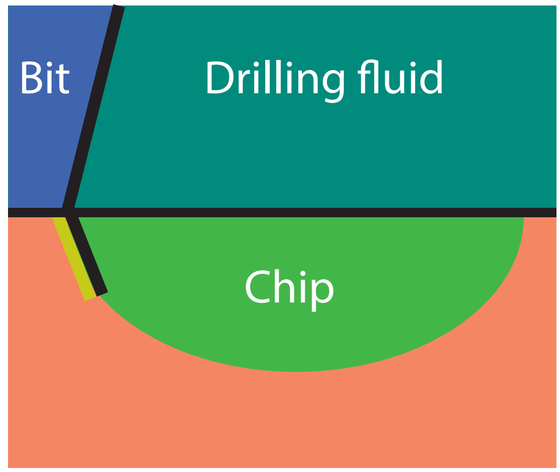


Figure 5-13: Bit tooth impacting rock.

The strongest limestone shown in Figure 5-11 is the Carthage marble. The weaker limestone is Indiana limestone. The sandstones are samples of Berea and a core from the Four Corners area of New Mexico. The shale is from Belly River, Canada. The shale strength is significantly lower than the sandstone.

5.5 Evaluation of various pore fluids

The strength of Indiana limestone could be changed by changing the pore fluids. Oil increased the strength; sodium azelate and sodium citrate decreased the strength; sodium adipate increased the strength. These data were discussed in the section on drill off. Surprisingly, however, with a roller-cone bit, the drilling rate decreased with sodium azelate and increased with sodium adipate. With a drag blade bit, the drilling rate increased with sodium azelate and sodium citrate and decreased with sodium adipate. The failure mode is also important when considering drilling rates. Even though sodium azelate decreased rock strength, it caused the rock to fail more malleably. See the discussion in the chapter on drill off tests.

5.6 Why do "weaker" shales drill more slowly than sandstone with roller-cone bits?

The question is sometimes asked: "Why do shales drill so much more slowly than sandstones with roller-cone bits, when they have about the same compressive strength in surface testing?" The answer should now be obvious from the discussion above. The description of the series of events that happen as a bit tooth is forced into a shale surface should explain the effect.

To drill, material from the crater must be removed by the drilling fluid. These pictures below portray the events as a bit tooth penetrates a rock.

When the pore pressure is maintained at the same pressure as the confining pressure, the failure is brittle and large chips fly from the surface (Figure 5-12).

Cracks below the tooth impact zone tend to fill with fluid. In a permeable rock, or a rock with gas in the pore space, fluid may be supplied from the formation. In impermeable rock, the pore space must be filled with drilling fluid or filtrate (Figure 5-13). Drilling fluid is designed to have a low fluid loss; therefore, the cracks are not filled rapidly. The lack of fluid to fill the pore space results in a significant decrease in pore pressure. The increase in rock strength and the change from brittle to malleable failure is a well-known effect in rock mechanics. As the cracks are generated, the pore pressure in the region decreases. The rock becomes stronger and fails more plastically as the next tooth impacts the area. The artificially created permeability and porosity also cause a filter cake to be formed on the surface of the crushed zone. This filter cake makes it difficult for the chips to be removed. In cases like this, increasing the rotary speed on "soft-formation" bits tends to scrape the filter cake away and will increase the founder point.

As the fracture starts beneath the bit tooth, it must be filled with fluid. If no fluid is available to fill the crack, the pore pressure around the fracture decreases. The rock becomes stronger and starts to fail malleably. Cuttings will become much smaller and drilling rate will decrease.

The plastic nature of the rock is only a downhole condition. When the chips, cuttings, sloughings, or cores arrive at the surface, the pore pressure and the confining pressures are equalized. The rock becomes brittle. The rock downhole may also retain some of its abrasive characteristics even though it does fail in a plastic manner.

Extended nozzles have the effect of increasing the jet velocity at the bottom of the hole. High jet velocities assist removal of the crushed material adhering to the bottom of the hole. Decreasing the drilling fluid plastic viscosity will also promote better removal of the debris beneath the drill bit.

Feenstra and van Leeuwen describe bottom balling in hard rock drilling. "The bottom becomes covered with a layer of crushed material, which is clearly visible on inspection." These were laboratory tests with full-scale bits drilling under pressure. "This phenomena is most pronounced when non-friable rock is drilled with an insert bit, which has a crushing action."

Drilling rates on the order of 10 ft/hr with a rotary speed of 100 rpm means that the bit is advancing about 0.02 in. per revolution.

$$\frac{(10\ \text{ft/hr})\ (\text{hr}/60\ \text{min})\ (12\ \text{in./ft})}{(100\ \text{rev/min})} = 0.02\ \text{in./rev}$$

Equation 5-2

Drill bit teeth are always longer than ⅜ in. Clearly the drill bit teeth do not remove ⅜ in. of rock with each revolution.

The layer of crushed rock and mud solids certainly would inhibit the drilling rate of an insert bit. The existence of a "cake" on a permeable sandstone is easily visualized even with a clean surface at the bottom of the borehole. The fractures caused in the rock by the action of the bit apparently create void space or porosity and permeability — at the surface of even impermeable hard rock.

5.7 Testing shale cores

Shales, with their lower permeability and reactive matrix, present a greater challenge for students of rock mechanics. The mechanical aspects of limestone failure should be prevalent in shales and will suggest behavior without the encumbrance of the reactive nature of clay platelets. Shales have porosity similar to the Indiana limestone. The low permeability shales probably fail much like limestone, except that the clay is interactive with the fluid in the pore space. Changes in salt content, or exposure to fluids different from the interstitial fluid in the shale, can change the shale behavior.

Pore pressures within the samples of rock do not remain constant after the rock yields unless additional fluid is injected into the sample. The force-deformation curve for Indiana limestone with a 10,000-psi confining pressure and a 5,000-psi pore pressure rises in a straight line until yield is reached. After the rock yields, the deformation continues at the same force, if fluid is rapidly pumped into the specimen. A deformation of ¼ in. in a ¾-in. long core requires that about 1,000% of the original pore volume be injected into the rock to maintain pore pressure constant at 5,000 psi (Figure 5-8). The rock is dilatant. The shear planes generated within the rock create additional pore space. Any testing of rock samples past the yield point must have a means of rapidly injecting fluid to maintain constant stresses within the rock. The fluid must flow through the cone of fracture to reach the part of the core which is deforming. The permeability in the cone of fracture is unchanged during the test. When testing shale cores, sufficient time must be allowed to move fluid through this very impermeable region. Any testing of rock samples past the yield point must have a means of rapidly injecting fluid to maintain constant stresses within the rock. This is difficult even with the Indiana limestone or Berea sandstone cores. This is the reason that the rock failure data presented here is plotted in terms of yield point instead of ultimate failure stress.

As the internal pressure changes above the cone of fracture, a delay in detection results and injection of fluid into the cylinder is probably not possible using strain rates reported in the literature. This casts serious doubt about the ability to determine the octahedral shear stress and the normal stresses at failure.

Shales and low permeability limestones have many features in common and some major differences. Shales have clay platelets that are reactive with interstitial fluids whereas limestones are relatively inactive with fluids with a basic pH. For example, when salt is added to a bentonite (or montmorillonite) slurry, the pH decreases. Cations of all types are found in the clay matrix. Specifically, the sodium interchanges with hydrogen ions because of the sodium equilibrium with ions on the clay surfaces. Extrapolating this to other situations, if the ionic content of the water surrounding a shale could be maintained in the same ratio as the ionic content of the clay matrix exposed to the water, no ionic interchange would take place.

Shales deform and fail in a similar manner but the strength properties are much more difficult to determine. The clay surfaces within a shale react with water and salts to change the internal pressure within the shale. Pore pressures applied to shales require long times to equilibrate. At failure, liquid cannot be supplied to the failure planes fast enough to maintain a constant pore pressure. The permeability of the Indiana limestone was around 4 or 5 millidarcy; whereas shales have permeability of the order of a micro-millidarcy. As many as seven days were required to transmit pressure from the bottom of a 1 ¾ in. long shale core to the top of a shale cylinder. The reactive nature of the clays within shale cores plague investigators. Results published in the literature vary greatly depending upon the shale handling and history.

Shales exposed to the atmosphere gain or lose water, depending upon the relative humidity. Attempts to maintain shale samples in a controlled relative humidity that matches their desire for water, result in evaporation of water from the core and air intrusion into the core. Some shales have about

10% - 20% porosity. Placed in a chamber with a relative humidity to match the clay's desire for water causes the water in the larger pore spaces to evaporate. A saturated sandstone core placed in a desiccators with a 75% relative humidity would soon lose most of the water in the pore spaces. Drying the cores drastically changes their reaction to water. Shale strength information should be evaluated within the context of the handling and sampling procedures used.

The electron microscope picture of shale (Figure 5-14) reveals some surprising holes and porosity which are not visible without the magnification. The small white bar in the bottom right corner of the bottom right picture is one micron long. The area is an enlargement of a portion of the other pictures (Figure 5-15). The tunnel would seem to be very large compared to a water molecule. A water molecule has dimensions in the order of 3-5 angstroms. The tunnel is about five microns or 50,000 angstroms in diameter. Perhaps this comparison would be easier to envision if the dimensions were changed to feet. A 5-ft tall person would have no trouble entering a "tunnel" or cave 50,000 ft (or over nine miles) high. A drill bit creates a few micro-cracks in the side of the wellbore. These cracks can connect several of these caverns and admit fluid. The exposed clay platelets can slowly imbibe this fluid and expand.

5.8 Strength test of shale cores

One study of shale properties reported storing the shale in desiccators with an atmosphere that matched the relative humidity (or fugacity) of the shale. Some data has been presented on the strength of shale after they have had their water removed from the pore spaces while maintaining the water associated with the clay. These cores were stored in a relative humidity environment which matched the shale's

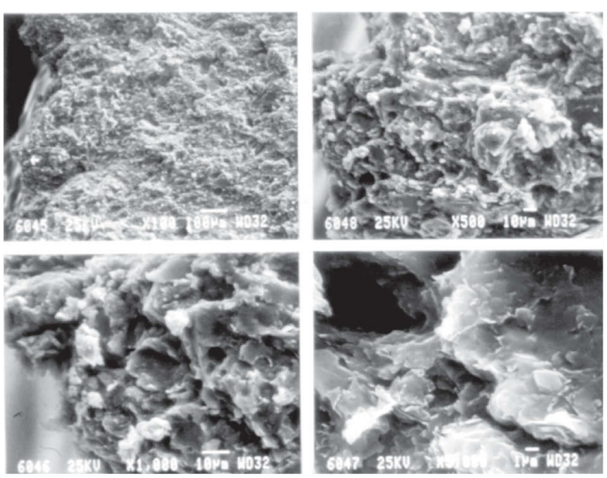


Figure 5-14: Shale porosity.

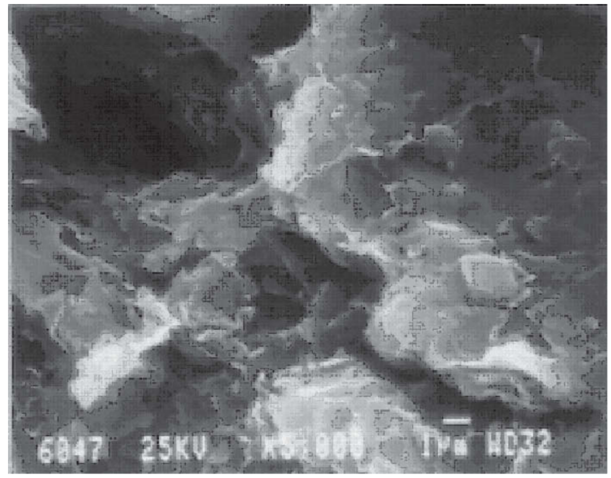


Figure 5-15: Hole in a shale.

activity. Water, however, in the large openings would evaporate from the core. In order to develop a pore pressure in these tests, the rock was compressed until a drop of mercury at the lower extremity of the core would read the pore pressure. Obviously, much of the open pore space in the core had collapsed before the triaxial test was performed.

In another study, much of the rock strengths were reported for cores which had a "splitting" mode of failure. When a cylinder of rock splits upon failure, usually the ends of the core sample are not parallel. This results in a much lower strength than will be found when the core actually compresses and fails in shear.

5.9 Strength of rock

If the failure strength of a rock is unknown, failure stresses of the rock in a wellbore cannot be calculated. This can best be illustrated by calculating the burst pressure of a sample of line pipe. If the sample strength is determined from some other material other than the pipe material, the result may be very confusing. Determining the strength of a rock sample when the rock sample no longer resembles the material in the formation is exactly the same scenario. Frequently, imperfections, such as micro-cracks in the formation, are significant in in situ failure but cannot be duplicated in the laboratory. Many papers appear which attempt to predict wellbore stability stresses but do not agree with each other.

If the handling procedure changes the failure mode and criteria, the in situ failure stresses are probably not known. Most failure models use cylinders of rock and few use wellbore-shape configurations. Questions concerning intermediate principal stresses and equivalency conditions cast doubt on the validity of most measured failure conditions, even the one shown above. These samples were from a shale core that had been preserved at the well site by wrapping in aluminum foil and covering with paraffin. The pore pressure was applied by introducing a brine solution. However, the brine solution was not the same mixture of ions as was present in the shale. Consequently, the introduction of the brine could have affected the results obtained.

Reactions with water and various salts can create a confusing picture when comparing laboratory test results of different investigators. The storage, handling, and preparation procedures used for various shale samples seem to determine laboratory results. Undoubtedly shale exhibits all of the characteristics of a low-permeability, fine-grain limestone in addition to some other unique characteristics. Cores brought from the sub-surface experience an expansion of the matrix. Changes in salt content, or exposure to fluids different from the interstitial fluid in the shale, can change the shale. Surface samples of shale probably do not replicate the behavior of samples that have been buried for millions of years.

Observations from thin sections of failed Indiana limestone indicate that the failure planes cease to pass between grains and start passing through the grains as the pressure differential increases. This probably also accounts for the significant increase in strength and the movement toward more malleable failure modes of this rock as the differential pressure increases.

Compression tests of rock cylinders in which the pore pressure is significantly lower than the confining pressure should observe the pore pressure increasing slightly during the elastic deformation of the sample. After yielding, the pore pressure will decrease rapidly as the rock deforms. The cylinder of rock will form a cone of fracture adjacent to the platens compressing the rock. This cone is created because the friction forces between the platen and the rock cylinder prevents the cone from expanding laterally. The sides of the cylinder expand, but the ends do not. This creates a shear stress at the outside end surface of the cylinder. The rock fabric within this cone of fracture does not fail. If pore pressure within the rock cylinder is measured through the cone of fracture, the rock matrix must have sufficient permeability to transmit that pressure and allow fluid to be injected into the rock to maintain pore pressure after yielding. Obviously, this creates a serious problem for shales with their nanodarcy permeability. As the internal pressure changes above the cone of fracture, a delay in detection results and injection of fluid into the cylinder is probably not possible using strain rates reported in the literature. This casts serious doubt about the ability to determine the octahedral shear stress and the normal stresses at failure.

Shale failure characteristics are measured in the laboratory to provide information for various models of wellbore stability. Shale samples from surface quarries may, or may not, replicate the behavior of the same rock when it has been buried during a couple of million years. Sampling the shale from depth is difficult because the tectonic stress have been relieved.

5.10 Ionic interchange with clay in shale

Another problem arises with the requirement that fluid needs to be injected into a shale core. This can be explained by considering the behavior of bentonite in water. Bentonite is a very active clay and is similar to the clays found in some shales. When salt (sodium chloride) is added to water, the pH does not change. (There is no change in hydrogen ion content.) When salt is added to a bentonite aqueous slurry, the pH decreases. The decrease in pH indicates an increase in hydrogen ion content. This is caused by a mass balance equilibrium change as more sodium ions are exposed to the clay surface that was in equilibrium with the ion content in the water around the clay platelets. An exchange takes place that moves some of the sodium ions onto the clay platelets and removes some of the other positive ions from the clay. Many positive ions may be found on clay platelets: sodium, calcium, magnesium, lithium, cesium, and hydrogen. This indicates that injecting a liquid solution into a shale to maintain pressure may alter the nature of the clay surfaces in the shale.

Injecting a brine solution into the shale for pore pressure control will not only require a significant amount of time for pressure equilibration but will also change the material being tested because of the activity of the clays in the shale. The rock properties for limestone changed depending upon the chemicals in the pore fluid. Changing the pore fluid in a shale will probably have that same effect or an even larger effect because of the cation exchange just discussed.

Shale failure characteristics are measured in the laboratory to provide information for various models of well-bore stability. Shale samples from surface quarries may, or may not, replicate the behavior of the same rock when it has been buried during a couple of million years. Sampling the shale from depth is difficult because the tectonic stress have been relieved. Observations of shale failure results by a variety of laboratories seems to suggest that the failure stresses are as much a function of the preparation and handling of the shale before the tests as they are of the properties of shale.

5.11 Rock properties and wellbore instability

Wellbores become unstable for two primary reasons: chemical instability and mechanical instability. Shales are difficult to study in the laboratory because they experience both types of instability. Mechanical instability can be evident in almost any sedimentary rock. Rocks can fail in tension (resulting in lost circulation) or shear from compressive loading (resulting in cavings, tight holes, and stuck pipe).

5.12 Ballooning

In some formations, drilling fluid is lost when the pumps are turned on and is recovered when the pumps are stopped to make a connection. When the well starts flowing with the pumps off a kick might be anticipated. Usually, a BOP is closed and the "kick" circulated out of the well. This can be time consuming. Frequently, the explanation involves the concept that the shale is expanding because of ECD and the wellbore acts like a balloon. The statement is usually followed with the comment that everyone knows that shale under pressure is plastic and the fact that sometimes the shale squeezes into the wellbore and binds the bit.

Observing the shape of the rocks compressed with a high differential pressure (Figure 5-16), indicates that the statement about plastic behavior is correct. HOWEVER, when the compressive load is removed from the samples, they did not return to their original length. The rock cores did return to their original lengths before failure, because they are elastic.

The movement of shale into the wellbore (i.e., plastic flow into the wellbore) should result in some shale intervals being under-gauge when calipered. In 1972, a major operator started a worldwide search for any 10-ft section of shale that was under-gauge as shown on a multi-arm caliper log. To date, no reports of any such sections have been found. Salt does flow into a borehole — but shale does not creep that fast. Shale does creep. Some laboratory tests indicate that a couple of centuries would be required before the creep was sufficient to bind a drill bit. Limestone also creeps. Some of the benches on the campus of an Ivy League university have developed a noticeable sag in the middle of the bench during the past couple of hundred years.

The ballooning is apparently the results of the expansion of microfractures in the shale to form an extensive fracture around the wellbore. Some knowledgeable drilling supervisors found by experimentation that adding sulfonated asphaltenes to their drilling fluid tended to keep the borehole to gauge in some shale. Neal Davis, Chevron, explored that effect in the OGS laboratory and reported the results in SPE Drilling Engineering, March 1989, "New Laboratory Tests Evaluate the Effectiveness of Gilsonite Resin as a Borehole Stabilizer," Neal Davis II, and Clyde E. Tooman, pg. 47-56. Some scanning electron-microscope images indicated some of the asphaltenes embedded in the cracks around the wall of the borehole. Apparently, if the drilling fluid was unable to enter the small microcracks in the shale, the wellbore was more stable.

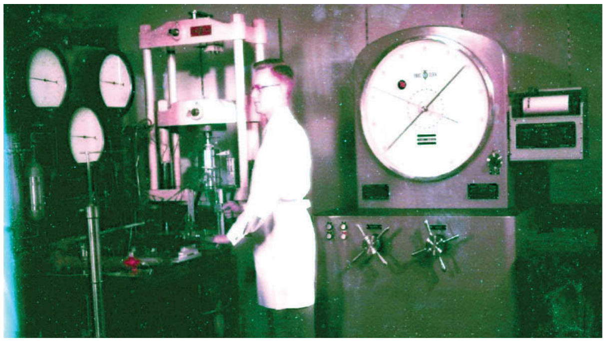


Figure 5-16: Triaxial compression testing of rock.

South of Lake Charles, Louisiana, formations are notorious for "ballooning." A well was drilled in this formation with a drilling fluid treated with a sulfonated asphaltene. No ballooning occurred. The problem, of course, is: "How do you prove something would have happened if it did not?" Until a controlled engineering study can be subsidized, this will still remain one of those "field practices" that may work.

5.13 Effective stresses

If the formation contains fluid (and most do), the liquid pressure in the pore space helps support the overburden stress. A concept of effective stress was introduced by Terzaghi in 1945. (Terzaghi, K., "Stress Conditions for the Failure of Saturated Concrete and Rock," Proceedings, American Society for Testing and Materials, Vol. 45, 1945, pp. 777-801.)

Usually the effective stress is written as an equation:

Effective overburden stress
= Total overburden stress Pore pressure

Equation 5-3

or

$\sigma_V = S_v - P_p$ **Equation 5-4**

The actual equation written by Terzaghi contained a constant in front of the pore pressure. In some rocks, the pore pressure is not totally effective in reducing the overburden stress. This constant is called "boundary porosity."

The effective stress concept, introduced by Terzaghi , has been used in many analytical evaluations of subsurface stresses. The effective stress defines the stress reduction between grains caused by internal pore pressure in a porous media. Frequently, the pore pressure is assumed to be 100% effective in decreasing a stress applied to a porous media. Terzaghi, however, defined a boundary porosity as "…the ratio of that part of the area of the potential surface which is in contact with the interstitial fluid and the total area of the surface." The values calculated by Terzaghi were close to unity. (As an aside, his paper also included a discussion of "splitting failure" by Mr. Kessler, National Bureau of Standards. Splitting failure of cylinders is now recognized as an artifact of the test method, such as non-parallel plattens, and not a correct failure mechanism.)

In 1942, Leliavsky, using unjacketed cement cores, reported that the interstitial fluid pressure appeared to act upon 92% of the surface of failure. He concluded that "The fraction of the area of cross-section over which the internal pressure acts can therefore have nothing to do with ordinary porosity, and the results of the experiments tend to support Professor Terzaghi's views."

John Handin, et al, found a boundary porosity of 100% for sandstone. Three conditions were found necessary to use the effective stress concept with 100% boundary porosity:

- The permeability is sufficient to allow pervasion of the fluid and furthermore, to permit the interstitial fluid to flow freely in and out of the rock during the deformation so that the pore pressure remains constant;
- The rock is a sand-like aggregate with connected pore space;
- The interstitial fluid is inert relative to the mineral constituents of the rock so that the pore pressure effects are purely mechanical.

Ralph Kehle addressed the concept of "effective stress" with the equation:

$$\sigma_{ij\text{-Effective}} = S_{ij\text{-Total}} + kP_p\delta_{ij}$$ **Equation 5-5**

Where:

k is the boundary porosity

P_p is the interstitial pore fluid pressure

δ_{ij} is the Kronecker delta (The Kronecker delta is zero when i does not equal j and equal to one when i equals j)

Kehle indicates that "many attempts have been made to determine values for effective boundary porosity, and arguments as to its significance have been presented in the literature for more than twenty years. The measured values of the effective boundary porosity vary between 1.0 for a sphere pack at low pressures to about 0.85 for some sandstones loaded in a prescribed manner at high pressures."

The matrix octahedral stress, S, derived in the next section, is:

$$S = (P_v / 3) + P_c - (P_p)\,[1 - (A_G / A_s)]$$ **Equation 5-6**

$$S = \frac{P_v}{3} + P_c - P_p\left(1 - \frac{A_G}{A_S}\right)$$ **Equation 5-7**

Where:

P_v is the vertical pressure or stress applied to a cylinder

P_c is the confining pressure

P_p is the pore pressure

A_G is the grains in the failure plane

A_s is the area of the failure plane

(The matrix octahedral stress has been called the Rocktahedral stress.)

Equation 5-6 can be verified at the two extreme values of pore pressure.

Case 1: When the pore pressure is zero, the equation reduces to:

$$S = P_v /3 + P_c$$ **Equation 5-8**

This is identical to values calculated for the normal stress (σ) by the octahedral stress theory.

Case 2: When pore pressure is the same as the confining pressure and no axial load is applied, Equation 5-6 reduces to:

$$S = P_c\,\eta$$ **Equation 5 -9**

This is similar to Terzaghi's equation for boundary porosity.

Boundary porosity is defined mathematically as:

$$\eta = \frac{A_G}{A_{SF}}$$ **Equation 5-10**

Where A_{SF} is the area of the surface of failure.

Equation 5-6 may be rewritten in terms of boundary porosity:

$$S = \frac{P_v}{3} + P_c - \eta\,P_p$$ **Equation 5 -11**

5.14 Calculation of boundary porosity

Mohr's condition for failure from the octahedral stress theory was described by Nadai.

$$\tau = f(\sigma)$$ **Equation 5-12**

This may be extended to the failure condition of a porous medium with a pore pressure by

$$\tau = f(S - \eta\,P_p)$$ **Equation 5-13**

If a rock fails at the same axial load, P_v, and at the same shear stress, τ, for two different combinations of pore and confining pressures, the boundary porosity may be calculated. The two situations may be defined as primed and unprimed stresses in the following equations:

$$S = \frac{P_v}{3} + P_c - \eta P_p \qquad \textbf{Equation 5-14}$$

and

$$S = \frac{P_v'}{3} + P_c' - \eta P_p' \qquad \textbf{Equation 5-15}$$

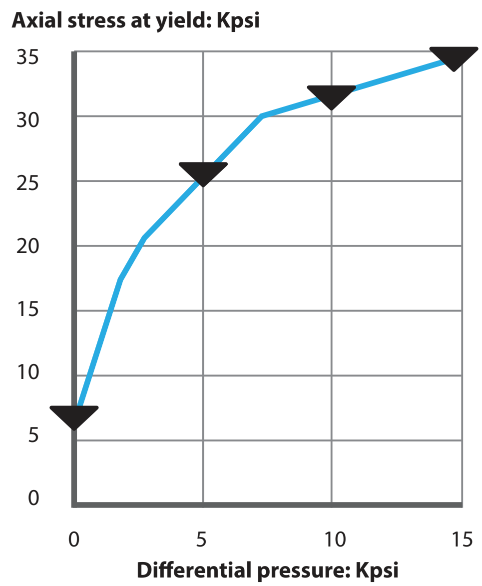
Since the failure shear stresses are equal if Pv = P'v, dividing Equation 5-13 by Equation 5-14 results in

$$\eta = \frac{P_c - P'_c}{P_p - P'_p} \qquad \textbf{Equation 5-16}$$

Thus, the boundary porosity in rock at failure may be calculated from a relationship involving confining and pore pressures for two conditions which produce failure at a given piston load. The boundary porosity indicates the fraction of the pore pressure across the failure plane which reduces the confining stress. Usually, most reservoir equations assume that the boundary porosity is 100%. This means that all the pore pressure is effective across the failure plane. However, for limestone and, presumably, shale, the boundary porosity is less than 100% or all the pore pressure is not effectively reducing the tectonic compressive stresses.

Picture Cliffs sandstone is a low permeability, shaly quartz rock from the Four Corners area of New Mexico. Failure data for this sandstone indicates that the yield strength depends only on the differential pressure (between the confining and pore pressures) and not on the absolute value of confining pressure, as shown in Figure 5-17. In such cases the boundary porosity calculated by Equation 5-15 is 100%. This means that the pore fluid pressure is 100% effective over the surface of failure of the rock. The failure plane apparently passes between the grains at the points of contact and does not

Table 5-1: Calculated values of boundary porosity for Indiana limestone.		
	Boundary porosity for different pairs of confining pressures	
Yield Stress 10^3 psi	$10X10^3$ psi $3X10^3$ psi	$5X10^3$ psi $3X10^3$ psi
8	100	100
9	98	95
10	93	91
11	91	88
12	88	84
12.5	86	82



Confining pressures: 5,000, 10,000 and 15,000 psi

Figure 5-17: Effect of differential pressure on the yield stress of Picture Cliffs sandstone.

pass through the grains. Visual examination of the failure surfaces indicates a very rough plane of failure.

Values of boundary porosity, calculated from Equation 5-15, indicate that the pore pressure may be effective over only 82% of the failure plane in some cases (Table 5-1).

As the pressure differential increases, the boundary porosity decreases. An insight into the behavior of shale might be gained by extrapolating the behavior of a low permeability limestone to a very low permeability shale. As the boundary porosity decreases, the shale would become stronger in compression but fractures would be created more easily. The stresses important to fracturing are the tensile strength of the material, and the stresses preventing the fracture from opening. Tensile strength of rocks is very low – on the order of a few hundred psi. The stress preventing the fracture from opening is the sum of the tectonic stress and the pore pressure if the boundary porosity is 100%. This is the case for sandstones, as demonstrated by the Picture Cliffs sandstone. This is the reason that lost circulation is common in "drawn-down" sands (or formations where the pore pressure has been reduced because of production.) If the boundary porosity is less than 100%, the pore pressure is not effectively applied across the failure surface. A fracture would be formed more easily if the pore pressure is not effective over the surface of the fracture. This effect could be responsible for the "ballooning" problem observed in some wells. When shale fails malleably, removal of the stresses do not return the shale back to the original shape. It is more likely that the

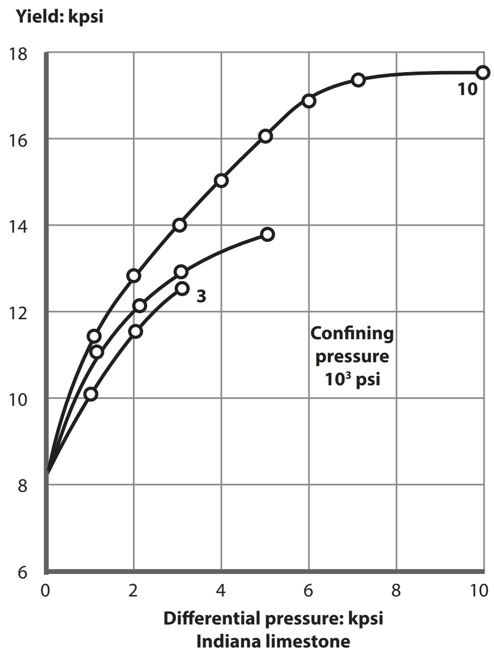


Figure 5-18: Effect of differential pressure on the yield stress of Indiana limestone.

loss of drilling fluid blamed on "ballooning" is caused by the fracturing of the shale not its "plastic" behavior.

This is a difficult problem to examine in a laboratory. First, the samples of shale are normally selected to be homogenous. Tests need to be repeatable and reproducible. The specimens must, therefore, resemble each other as closely as possible. If microfractures along the borehole wall are responsible for the fractures expanding, this is difficult to reproduce in a laboratory study. Next comes the question of the fluid to be used to control the pore pressure. As indicated earlier, most fluids interact with the clay matrix of the shale and change the properties of the material. Reproducing downhole conditions seems almost impossible.

Although proving something did not happen is a difficult, if not impossible task, field tests predicated upon sealing the fractures at the wellbore wall seem to prevent ballooning in formations which exhibited that trait previously.

References

1. Handin, J., Hager, R.V., Jr., Friedman, M., and Feather, J.N., "Experimental Deformation of Sedimentary Rocks Under Confining Pressure: Pore Pressure Tests," Bulletin, American Association of Petroleum Geologists, Vol. 47, 1963, pp. 717-756.

2. Kehle, R., "The Determination of Tectonic Stresses through Analysis of Hydraulic Well Fracturing," Journal of Geophysical Research, Vol. 69, No. 2, Jan. 15, 1964, pp. 259-272.

3. Leliavsky, S., "Uplift in Dams," Nature, Vol. 3770, 1942, pp. 137-138.

4. Nadai, A., Personal Communication, August 1958.

5. Nadai, A., "Theories of Strength," Transactions, American Society of Mechanical Engineers, Vol. 55, 1933, pp. A111-129.

6. Robinson, L.H., "Effects of Pore and Confining Pressures on Failure Characteristics of Sedimentary Rocks," SPE Paper 1096-G, presented at 33rd Annual SPE Fall Meeting, Houston, Tex, Oct. 5-8, 1958.

7. SPE Drilling Engineering, March 1989, "New Laboratory Tests Evaluate the Effectiveness of Gilsonite Resin as a Borehole Stabilizer," Neal Davis II, and Clyde E. Tooman, pg. 47–56.

8. Terzaghi, K., "Stress Conditions for the Failure of Saturated Concrete and Rock," Proceedings, American Society for Testing and Materials, Vol. 45, 1945, pp. 777-801.

Chapter 6
Carrying Capacity to Transport Cuttings to the Surface

TABLE OF CONTENTS

6.1 INTRODUCTION

After removing cuttings from the bottom of the hole, as discussed in Chapter 3, the cuttings should be brought to the surface as expediently as possible. Different procedures are required to transport cuttings through three different ranges of hole angles. The three different ranges are vertical wells up to about 35°-40°, intermediate angles from about 35°-60°, and high-angle holes from 60°-90°.

An empirical correlation has been developed for the vertical and almost vertical wells and tested worldwide with both water-based drilling fluids and non-aqueous fluid (NAF). This calculation is discussed in API RP 13D – Hydraulics and is called the carrying capacity index (CCI). A brief application guideline is presented below to facilitate application of the technology. The theory and equation development will be discussed in later sections along with hole cleaning for the other two hole-angle ranges. Most wells have a vertical section of the wellbore and the empirical relationship will be applicable to most wells

6.2 Summary

A summary of evaluating carrying capacity in vertical and near wells:

1. Use Equations 6-4 and 6-5 to determine value of K from PV and YP;
2. Use flow rate and maximum hole diameter to determine annular velocity;
3. Determine carrying capacity index (CCI) using Equation 6-6;
4. If the CCI is less than 1.0, calculate the K value needed to clean the hole:

$$K = \frac{400{,}000}{(MW)\ (AV)}$$

5. Change the yield point and determine whether some cuttings do not have sharp edges;
6. If some cuttings are still tumbling (do not have sharp edges), raise the yield point a small amount;
7. Evaluate drilled solids removal system to attempt to lower the PV. This will have the effect of raising K. See Chapters 12 and 13.

6.3 Applications summary for almost-vertical holes

For boreholes up to 35° degrees, the carrying capacity index (CCI) can be calculated from the equation below:

$$CCI = \frac{(K)\ (AV)\ (MW)}{400{,}000} \qquad \textbf{Equation 6-1}$$

Where:

K is the effective viscosity in centipoise (cp) from the power law rheology model
AV is the annular velocity (in ft/min)
MW is the mud weight (in ppg)

For boreholes up to 35°, the yield point needed to transport cuttings can be calculated. Annular velocities in a wellbore are established by the hydraulics optimization procedure (Chapter 3). The mud weight is normally determined by the pore pressures in the wellbore and, infrequently, by wellbore stability analysis. The only variable remaining to provide good hole cleaning is the viscosity or rheology. A minimum value of the K constant in the power law rheology model can be used to determine the drilling fluid viscosity needed to bring cuttings to the surface, Equation 6-2.

$$K = \frac{400{,}000}{(MW)\ (AW)} \qquad \textbf{Equation 6-2}$$

For boreholes up to 35°, the yield point needed to transport cuttings can be calculated. Annular velocities in a wellbore are established by the hydraulics optimization procedure (Chapter 3). The mud weight is normally determined by the pore pressures in the wellbore and, infrequently, by wellbore stability analysis. The only variable remaining to provide good hole cleaning is the viscosity or rheology. A minimum value of the K constant in the power law rheology model can be used to determine the drilling fluid viscosity needed to bring cuttings to the surface, Equation 6-2.

For example, if a 9.0-ppg drilling fluid is flowing up an annulus with a velocity of 60 ft/min, a minimum K value of 740 effective cp is needed to transport drilled solids out of the hole. If the fluid has a plastic viscosity of 10 cp, a yield point about 16-17 lb/100 sq ft will be needed to clean the hole. Use the graph in Figure 6-1 to determine the yield point. Adjust the yield point to the proper value and examine the cuttings on the shale shaker.

If some of the cuttings still do not have sharp edges, an additional increase in yield point will be needed. The constant (400,000) in Equation 6-1 could need to be as high as 600,000 in a few situations. In these rare cases, the K value would need to be 1,100 effective cp. This would require a yield point of around 20 lb/100 sq ft. While this seems like a small change in yield point (17 to 20 lb/100 sq ft), the impact on solids removal will be very large. The change required in the constant may be caused because the hole diameter is not the same as the drill bit. Washouts occur downhole and cuttings must still be transported past these regions of low annular velocity.

One significant paper by Sifferman, Myers, Haden and Wahl,

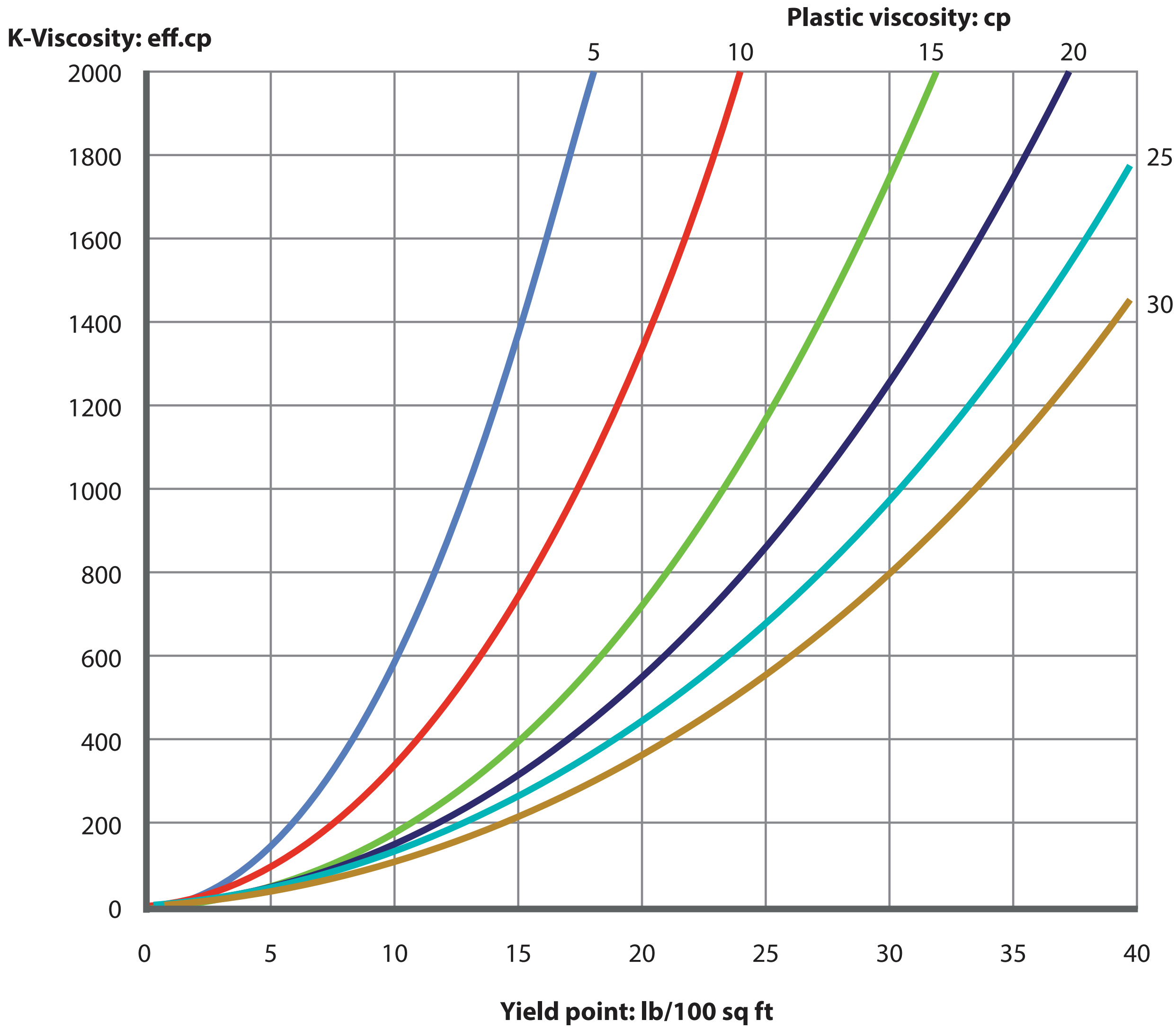


Figure 6-1: Viscosity as a function of PV and YP.

"Drill-Cutting Transport in Full-Scale Vertical Annuli"[13], described laboratory tests in which artificial cuttings were made with two different densities and three different sizes. They presented their results in terms of a cuttings transport ratio (the ratio of the velocity of the cuttings to the velocity of the fluid). This ratio is also equal to the ratio of concentration of cuttings in the feed to the cuttings in the annulus. In other words, the transport ratio represents the "storage" of cuttings. Figures 6-2 and 6-3 were originally published in their paper and are reproduced here with permission in Figure 6-2. The low annular velocities required to transport cuttings with the thick drilling fluid evoked considerable controversy when the paper was published.

An interesting comparison of the CCI can be made with published data from Sifferman, et al. The drilling fluid had the properties listed in Table 6-1.

CCI values are indicated on the chart and indicate an excellent agreement. The maximum value of the CCI is 1.5 for the highest value of the annular velocity for the thick drilling fluid.

Frequently the K value can be decreased without creating problems in the well. This will decrease the equivalent circulating density. Again, an examination of the cuttings will provide clues concerning the ability to clean the borehole.

Table 6-1: Drilling fluid properties used in Sifferman's experiments.

Description	PV	YP	Initial Gels	10-Min Gels	K-values
Thick Mud	16	37	60	29	2520
Inter. Mud	14	21	66	22	870
Thin Mud	8	8	84	3	210
Water	1	0	83	0	1

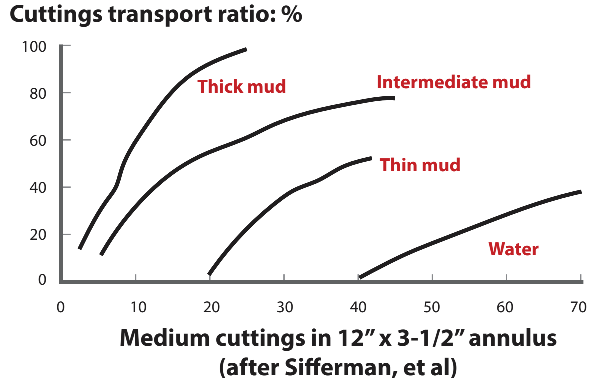


Figure 6-2: Cuttings transport for different fluids.

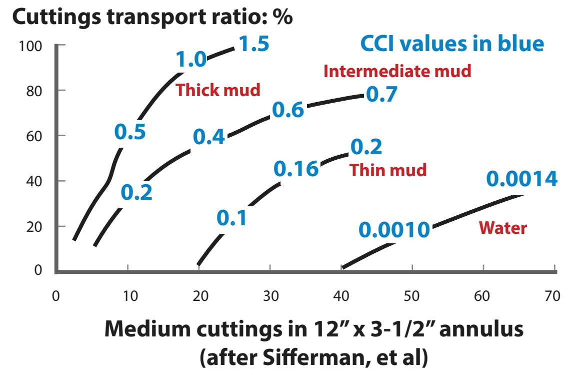


Figure 6-3: Comparing carrying capacity index (CCI) with cuttings transport ratio.

6.4 Theory and discussion

In two previous chapters, the founder point was identified and the hydraulics established to remove the largest cuttings possible from beneath the drill bit. The hydraulics optimization process also established the flow rate for the wellbore. The next step to obtain the best performance possible from any drilling rig is to efficiently remove the cuttings from the wellbore. When cuttings are tumbling in the annulus, small debris is formed with the disintegration of the cuttings. This will increase the plastic viscosity and also eventually create problems with filter cakes and founder points.

Plastic viscosity is the viscosity the fluid would have at an infinite shear rate. (See Chapter 14 for a discussion.) This controls the removal of cuttings from beneath the drill bit. Plastic viscosity should be as low as possible to remove the cuttings efficiently and expeditiously from beneath the drill bit. Decreasing plastic viscosity also increases the K value as observed in Figure 6-1. Select a yield point of 10 lb/100 sq ft in Figure 6-1. As the plastic viscosity decreases from 15 cp to 10 cp to 5 cp, the K-value increases from decreasing the plastic viscosity increases the yield point from 190 eff.cp to 250 eff.cp to 600 eff.cp.

Transport of the cuttings correctly is the first step in good solids control. Cuttings should reach the shale shaker with sharp edges, not as round balls.

When cuttings are not being transported effectively up the annulus, they tend to slump when the mud pumps are turned off to make a connection. A driller frequently interprets this as an indication that the "hole is creeping in and holding the drill bit". Actually, the concept of the "hole closing" because shale is creeping into the wellbore is a common myth perpetuated by feelings rather than facts. Most shales have a tendency to fall into the hole and enlarge the hole diameter instead of decreasing the hole diameter. Very few, if any, caliper logs have indicated a decrease in hole diameter in a shale formation. Salt formations do slowly creep, or flow, into the wellbore. Deep, hot salt formations can eventually close the wellbore completely. Consolidated clay or shale formations do not flow into the wellbore. The clays tend to absorb water and expand. This expansion creates a tensile load in the shale formation and the wellbore enlarges.

6.5 Vertical wells up to an angle of 35°

The angle of repose of drilled solids, or sand, is around 42°. This means that cuttings added a pile of drilled cuttings at angles greater than this will continue to slide down the slope. High-angle wells need other criteria to predict hole cleaning. Experiments have shown that the angle at which cuttings start sliding down a rough inclined hole is somewhat higher than 42°, as shown in Table 6-2.

Table 6-2: Angle of repose.

Fluid	Slide Angle
Water	42°
Gel and Water	45°
Diesel Oil	62°
Diesel Oil and Emulsifier	66°
85/15 oil-base drilling fluid	67°

In a vertical or nearly vertical well, only three "hole cleaning" variables can be controlled:

- Mud weight;
- Annular velocity;
- Drilling fluid viscosity.

Increasing any one of these variables increases hole cleaning. An empirical development created a carrying capacity index (CCI) for holes less than 35-40° from vertical. These boreholes are somewhat easier to clean because solids can settle a long distance before reaching bottom. The limit on the hole angle might be raised if the drilling fluid is NAF.

The weight (MW) should be the pressurized mud weight.

The annular velocity (AV) selected should be the lowest annular velocity in the borehole. Usually the mud report will indicate the annular velocity in the open hole and it is usually not the lowest annular velocity in the system. The annular velocity may be calculated from Equation 6-3.

$$AV = 24.51 \frac{Q}{\left[D_2^2 - D_1^2\right]} \qquad \textbf{Equation 6-3}$$

Where:

AV is the annular velocity, ft/min
Q is the flow rate in gpm
D_2 is the inside diameter of the casing, in.
D_1 is the outside diameter of the drillpipe, in.

Charts for estimating annular velocities, as shown in Appendix 6A, assume a generic pipe thickness. For more accurate numbers, use the actual casing dimensions to determine the inside diameter of the casing. The inside diameter of a 9 ⅝-in., 32.2-lb/ft casing is 9.001 in., whereas the inside diameter of a 9 ⅝-in., 75.6-lb/ft casing is only 8.031 in. The generic inside diameter will provide some reasonable guidelines. For accurate results, manufacturers can provide actual dimensions. These are not really necessary because the equations are not very accurate. Frequently, the lowest annular velocity is in an interval of hole that has enlarged because of wellbore collapse.

The viscosity should be a low shear rate viscosity (K). Hopefully, the drilled solid is moving upward with about the velocity of the drilling fluid, so the shear rate between the solids and the drilling fluid is very low. This low-shear-rate viscosity can be estimated by using the K value of the Power Law Model:

$$\text{Shear Stress} = K\,(\text{Shear Rate})^n \qquad \textbf{Equation 6-4}$$

CCI can be calculated from the equation below:

$$CCI = \frac{(K)\,(AV)\,(MW)}{400{,}000} \qquad \textbf{Equation 6–5}$$

Good hole cleaning results when CCI is equal to at least a value of 1. The cuttings should have sharp edges and large chunks should come to the surface. When CCI has a value around 0.5, cuttings will be well rounded and generally very small. If CCI is less than about 0.3, grain-size cuttings will arrive at the surface. Small cuttings with rounded edges indicate that a large number of solids have been added to the drilling fluid that cannot be removed with a shale shaker.

The 400,000 constant is an empirical number and is not very accurate. This means that CCI values are only approximate. The constant could be 380,000 or 420,000. For this reason, the equation is used primarily as a guide in the field. Drilling fluid properties are changed to provide the correct K viscosity. Cuttings are examined to see if any cuttings have retained rounded edges. The value of CCI may need to be 1.2 instead of 1.0 to obtain good hole cleaning.

Examine the cuttings arriving at the shale shaker. Edges should be sharp and not rounded. If the wellbore is stable, large cuttings may not come to the surface. Most large cuttings come from the side of the hole. Drill bits generally make small cuttings and they get smaller as the pressure differential across the bottom of the hole increases. Some laboratory measurements indicated that 90% of the cuttings created by a diamond bit drilling limestone were smaller than 44 microns (screen: API 325).

6.6 Calculating K

The viscosity value used in this equation is the K value viscosity from the power law rheological model:

$$K = [511]^{(1-n)}\,[PV + YP] \qquad \textbf{Equation 6-6}$$

and

$$n = 3.222 \,\text{Log}\left(\frac{2\,PV + YP}{PV + YP}\right) \qquad \textbf{Equation 6–7}$$

In the equation, the term (PV +YP) is actually the 300-rpm viscometer reading and 2 PV+YP is the 600-rpm reading. In this form, K is the viscosity at one reciprocal second shear rate. Some literature refers to PV+YP as a viscosity in the power law model. PV+YP is simply a method of reconstruction of the 300-rpm value read on a concentric cylinder viscometer.

The value of K appears with many different units in the literature. Since it is a ratio of shear stress to shear rate raised to an exponent, the unit should reduce to the unit of centipoise if the value of "n" is one. (This would be Newtonian fluid.) A viscosity described by a unit of pound-seconds per 100 sq ft would have very little meaning to most people. Most people can relate to a viscosity in centipoise. The viscosity in the metric system is the "poise", which is 1 dyne-sec/sq cm. The viscometer readings can be converted into units of poise or centipoise. (See the rheology discussion in Chapter 13.) Multiplying the shear stress reading by 5.11 changes the value to dyne/sq cm and multiplying the RPM by 1.7 changes the viscometer speed to reciprocal seconds. In this discussion, the values of the viscometer at 300 rpm will be used. The 300-rpm reading is the same as the sum of the plastic viscosity and the yield point. The shear rate for the 300-rpm reading is 511 reciprocal seconds. Using these values, the units of K become poise or centipoise for Newtonian fluids when n is equal to one).

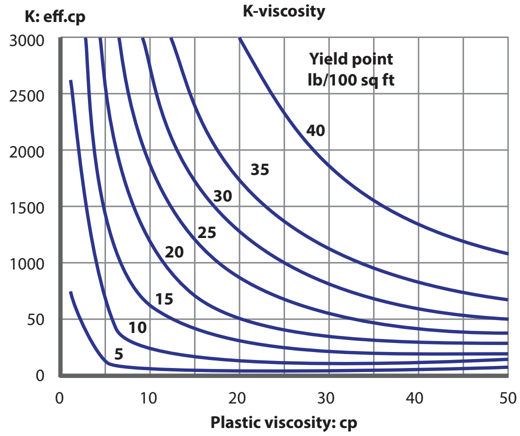


Figure 6-4: K Viscosity as a function of plastic viscosity for various yield points.

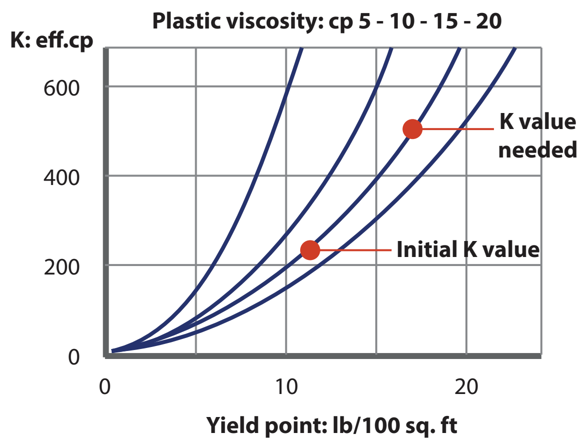


Figure 6-5: Finding yield point needed to make CCI equal to one.

For convenience the simple chart, Figure 6-1, can be used to obtain the value of K for various combinations of PV and YP. The K-viscosity chart can be used to determine K instead of the equations. Figure 6-1 also makes it easier to calculate a yield point needed to develop a specific value of K when the PV is known. The constant, 400,000, is accurate to only the first significant figure; therefore reading the K value from the graph will be sufficiently accurate.

Another interesting feature of this chart is the fact that changing YP is not the only rheology parameter which will increase K. For example, select a value of 15 lb/100 sq ft of YP. The value of K for a 20-cp PV is 300 effective cp and the value of K for PV equal to 10 cp is 600 effective cp. (Calculations using the equations will show 306 and 618.) The point is that decreasing the plastic viscosity doubled the K value. This means the cuttings will come to the surface more rapidly and without grinding. This will further decrease PV and additional benefits will accrue.

Replotting the K value as a function of PV instead of YP demonstrates the influence of plastic viscosity. Select a K value of 1,000 effective cp in Figure 6-4. This can be achieved with a variety of drilling fluid properties: 10 YP & 4 PV or 15 YP & 7 PV or 20 YP & 12 PV or 25 YP & 17 PV or 30 YP & 24 PV. Select a K value of 500 effective cp. This can be achieved by a variety of drilling fluid properties: 5 YP & 3 PV or 10 YP & 6 PV or 20 YP & 22 PV or 30 YP & 34 PV. Also observe that the effect of the value of the plastic viscosity greatly affects the way in which yield point changes the K value. For example, at a PV of 5 cp, a YP of 5 produces very little increase in K; however at a YP of only 10, the K increases to over 500 effective cp; at a YP of 15 the K value is close to 1,400 cp. With a PV of 20, YP of 5 has a very low K value; with a YP of 15, the K value increases to around 700 cp. This demonstrates the importance of keeping PV as low as possible. (Do that by removing drilled solids.)

Figure 6-4 makes it easier to visualize what happens frequently on some drilling rigs when a hole in the shale shaker screen is ignored. As the solids increase in the drilling fluid, the plastic viscosity will increase. The retort measurements are usually not sensitive enough to signal a significant increase in drilled solids content in weighted drilling fluids. As the plastic viscosity increases, the yield point needed to clean the borehole will also increase.

Failure to increase the yield point allows the solids in the annulus to tumble and have rounded edges. The material which grinds off of the cuttings further increases the plastic viscosity. This increases the problem of cuttings transport which means that more cuttings will have rounded edges. This increase in plastic viscosity will decrease the founder point of the bit. Furthermore, these solids will create a very poor filter cake. The torque and drag on the drillstring will increase, which offers a great chance that the pipe will become differentially pressure-stuck in the hole. The filter cake will interfere with logging operations and properly planting the casing string in the hole. This is a problem that keeps getting worse as more drilled solids are demolished into smaller solids.

Once the drilled solids transport is improved, the plastic viscosity will start to decrease and drilling problems will also decrease. The problem can be recognized on a drilling rig when cuttings start losing their thin, sharp edges. Usually, the PV increase will be very small at first and so subtle that it is not usually visible unless this variable is plotted daily. The first remedy on a drilling rig should be to pump a viscous sweep and remove as many drilled solids from the storage in the wellbore.

6.6.1 Using the correlation

From a practical viewpoint the K value chart is used in the field to determine what value of yield point is needed to clean the hole. To illustrate the use of the equation, consider a 12.0-ppg drilling fluid with PV = 15 cp and YP = 12 lb/100 sq ft flowing at 68 ft/min in the casing/drillpipe annulus. The "K" value from the chart is 250 cp. The carrying capacity index (CCI) would be:

$$CCI = \frac{(12.0\ \text{ppg})\ (68\frac{\text{ft}}{\text{min}})\ (250\ \text{eff.cp})}{400{,}000} = 0.5$$

Equation 6-8

The value less than one would indicate very poor hole cleaning. The CCI equation could be solved graphically for the value of K needed to clean the hole:

Figure 6-5: Finding yield point needed to make CCI equal to one.

$$K = \frac{400{,}000}{(13.6) \times (62)} = 470\ \text{cp}$$

Equation 6-9

If the plastic viscosity is unchanged, the K viscosity could be increased to 470 cp by increasing the yield point to about 20 lb/100 sq ft (Figure 6-5).

6.6.2 Diagnostics

The correlation can also be used as a diagnostic tool. Consider a typical drilling situation. (This was an actual case history — the names of the participants and the company are not revealed to protect those guilty of an erroneous reaction.)

Drilling at 11,500 ft with a synthetic oil drilling fluid, the annular velocity next to the 4 ½-in. drillpipe was 130 ft/min. Formation pressure is 9.4 ppg equivalent and the mud properties are 9.5 ppg; PV, 17 cp; and YP, 10 lb/100 sq ft, with gels 4/8.

The driller reported that drag on connections was increasing. When making a connection, the hole would close up when the pumps were turned off and more mud weight was needed to hold the formation back. The shale was closing up at the bottom of the hole.

The company had a discussion with a borehole stability expert who analyzed the problem and supplied some beautiful stress equations to solve the problem. The tectonic stress analysis indicated that an increase in mud weight to 13 ppg would "hold the shale back". The mathematical analysis and the computer program convinced the operations supervisor to apply the recommended solution immediately. The mud weight was increased to 13.0 ppg and in doing so, the drilling fluid properties changed to PV, 25 cp; YP, 15 lb/100 sq ft, with gels 6/10. After the drilling fluid properties changed, the driller reported that it was a success. The shale was no longer creeping into the well when the pumps were turned off. There was no drag on connections anymore. This sounds like a great success for borehole stability analysis — except for one "minor" point: the drilling rate with the IADC 537 bit decreased from 40 to 4 ft/hr.

In Chapter 5, rock properties are discussed. With proper differential pressure, rocks do fail in a plastic mode. After the rocks deform with a "plastic" behavior, they do not return to their original length when the load is removed. In diligent searches for evidence of an undergauge shale, no one has reported finding a caliper log with ten feet of shale undergauge. Generally, shales wash out, or fall into the well. When they expand, a tensile stress is created and they fail quickly and, frequently, in large chunks. The assumption that increasing mud weight will open "plastic" shale in a wellbore is a myth.

This was a classic hole cleaning problem. Cuttings on the shale shaker screen should have appeared to be well rounded. Calculate the CCI to confirm this:

For the 9.5-ppg drilling fluid:

$$CCI = \frac{(9.5\ \text{ppg})\ (130\frac{\text{ft}}{\text{min}})\ (175\ \text{eff.cp})}{400{,}000} = 0.54$$

Equation 6-10

If the driller had mixed a viscous slug of drilling fluid and pumped it around the hole, the drag forces would have diminished.

For the new weighted drilling fluid:

$$CCI = \frac{(13.0\ \text{ppg})\ (130\frac{\text{ft}}{\text{min}})\ (175\ \text{eff.cp})}{400{,}000} = 1.1$$

Equation 6-11

The carrying capacity increased so that the cuttings were being transported up the hole. Before the drilling fluid was treated, the cuttings were tumbling in the annulus. When the pump was stopped, these cuttings fell back downhole. This created a large drag force as the pipe was moved during the connection.

What change in rheology would have been required to clean the hole? Equation 6-12 can be used here by solving for the value of K:

$$K = \frac{400{,}000}{(MW)\ (AV)} = \frac{400{,}000}{(9.5\ \text{ppg})\ (130\frac{\text{ft}}{\text{min}})} = 325\ \text{eff.cp}$$

Equation 6-12

Using the chart in Figure 6-1, for a PV of 17 cp, the yield point should be around 14-15 lb/100 sq ft. Increasing the yield point from 10 lb/100 sq ft to the required value would require adding a very small amount of viscosifiers. The drilling rate would still be in the range of 40 ft/hr instead of requiring ten times longer to drill the well.

The problem with this actual case is the fact that the drilling crew thought they had correctly solved the problem. Since the contractor was on a day rate pay scale, the solution was very satisfactory with them.

Although it is not a standard measurement or observation on morning report forms, the cuttings on the shale shaker screens should be evaluated regularly. Good carrying capacity will bring the cuttings to the surface with the minimum amount of degradation. Look for cuttings with edges as sharp as a finger nail. Rounded cuttings indicate that the cuttings are tumbling. As they tumble, small pieces are broken off of the chip and this tends to increase the plastic viscosity.

6.7 Practical comments

Equation 6-1 is an empirical equation developed during many years of watching shale shaker screens while drilling. The value of 400,000 in the equation seems to match most of the data and observations from worldwide drilling operations with both water-based and NAF drilling fluids. This means that the values calculated are only accurate to the first significant number. Because of this, the values on the chart in Figure 6-1 do not have to be read to three significant figures. Make the calculation of what is needed, change the drilling fluid properties, observe the results and then modify the yield point again as required.

Note from the graph that a decrease in the plastic viscosity for any yield point will increase the K value. As solids are removed more efficiently, PV should decrease which will allow the YP to also decrease and still maintain good hole cleaning.

Good cuttings transport will result in cuttings appearing at the shale shaker which have sharp edges. Rounded cuttings indicate that cuttings are not being transported correctly.

As cuttings break apart, PV increases; this will cause a decrease in cuttings transport capability. If this continues for a long period of time, problems develop, such as poor drilling rates (lower founder points), stuck pipe (filter cake quality) and stuck pipe from cuttings falling downhole on top of tool joints, stabilizers, or drill bits.

In Equation 6-1, use the lowest annular velocity in the wellbore for the calculation. Morning reports usually list the annular velocity next to the drillpipe and drill collars in the hole being drilled. This is usually not the lowest annular velocity. The lowest annular velocity can be in the riser, or casing above the open hole, or in regions of enlarged hole diameter because of wellbore collapse.

6.8 Authors' comment

The CCI method is truly only an empirical method for determining hole cleaning. It was developed by observing cuttings on shale shaker screens for a period of about 5 years. The criterion for good hole cleaning was sharp edges on the cuttings. Frequently, the shaker screens would have a thick bed of well-rounded cuttings moving down the screen. In this case, the cuttings had been tumbled in the annulus and were not being transported properly.

The K value was calculated with the 300 rpm and 600 rpm dial readings because most morning reports will record the plastic viscosity and the yield point of the drilling fluid. Obviously, a low shear rate viscosity would be preferred. For accurate results, however, this viscosity would only be correct for a small range of temperatures around the measurement temperature of the drilling fluid sample. As in calculating pressure losses in drillpipes, this method suffers the same problem: the viscosity is generally unknown in most of the circulating system.

The actual viscosity of the drilling fluid in the annulus may not always be approximated by the yield point at the temperature used for the morning report. For this reason, the best hole cleaning may not be indicated by a CCI value of one but may require a value somewhat higher (like 1.2 or 1.3). The general procedure should be to calculate the K value needed for the well and observe the cuttings. If all of the cuttings do not have sharp edges, use the higher values. If, however, these cuttings are coming from a well with a long horizontal section, the cuttings may be damaged in that section of the hole. The CCI calculation does NOT apply to high-angle holes.

6.9 High-angle holes

Unfortunately, the empirical method just presented for holes up to 35° does not work for higher-angle holes. Most wells will have a vertical section and the CCI method will be a starting point for hole cleaning conditions. In high-angle and horizontal holes, flow rate and pipe rotation seem to be most effective. Turbulent flow seems to clean horizontal holes but fails to do so in wells between 35-60°.

Research has indicated that a viscoelastic fluid is very effective in cuttings transport in horizontal holes. The concentric cylinder viscometer has been modified to oscillate as well as rotate as described in Appendix 6B. The elastic and the viscous modulus of a fluid is determined by the in-phase and out-of-phase shear stress. Unfortunately, these moduli have not been explored sufficiently to provide guideline numbers to guarantee hole cleaning. Simply increasing the viscosity of the fluid in the shear rate range experienced in the annulus does not seem to be effective in providing good hole cleaning.

6.9.1 Cleaning holes with angles larger than 35°

Two factors are of primary importance when cleaning high-angle holes:

- Pipe rotation;
- Flow velocity.

6.9.2 Pipe rotation

Cuttings that settle to the bottom of a high-angle borehole will remain on the bottom no matter what fluid properties pass over the cuttings bed. Pipe rotation mechanically stirs the bed to move the cuttings into the flow stream.

6.9.3 Flow velocity

A rule of thumb prevalent in designing equalizing lines in a mud tank system is that the fluid velocity must exceed 5 ft/sec. This is equivalent to a velocity of 300 ft/min. In general a flow velocity of 200 ft/min in the annulus is difficult to achieve. However, when combined with mechanical agitation (pipe rotation), cuttings can be transported through horizontal sections of wellbores.

6.10 Intermediate hole angles (35-60°)

Holes with angles from about 35-60° are the most difficult to clean. Cuttings beds formed along the bottom of the hole are unstable and tend to avalanche down the hole. This movement can occur while circulating drilling fluid but it most often occurs when the pumps are stopped.

Dr. A. E. Boycott, a physician in England, noted that blood platelets settled faster to the bottom of a test tube if the test tube was inclined. Frequently, the process also works in a reverse manner when a gas bubble enters the wellbore during a trip. “Bottoms-up” gas frequently arrives at the surface much sooner than it would in a vertical well at the same vertical depth.

Boycott settling occurs even if the drilling fluid is moving. Generally, flowing drilling fluid does not have the same suspension characteristics of a quiescent fluid. (Remember “shear thinning”?) Pipe movement and annular velocity will assist in moving cuttings through this interval even though they are settling.

Under some static conditions, drilling fluids with insufficient suspension characteristics will even separate so that a clear liquid layer appears at the top of an inclined, simulated wellbore. The cuttings fall vertically downward and form a cuttings bed along the bottom of the wellbore. At these angles, the angle of repose of the cuttings is exceeded by the hole angle and the cuttings bed slides down the wellbore.

The “classical” approach to transporting cuttings has been to use a “slip-velocity”. Many PhD degrees have been awarded for studies of the various rheology models that predict hole cleaning. The settling velocity of a cutting is a function of many variables, such as: geometry, cuttings concentration, fluid velocity, fluid density, cuttings density, cutting size, cuttings shape, drilling fluid rheology, fluid temperature and probably others. Because of the complexity of the interactions of all of these variables and the problem with identifying them, the “classical” method will not be discussed here.

6.11 Holes with very high angles (60-90°)

As mentioned above, settling in a horizontal pipe is very difficult to prevent. Cuttings are easily deposited. Generally sweeps of high and low viscosities do not move these cuttings. The cuttings must be mechanically agitated back into the flow stream in the annulus. This requires pipe rotation and pipe movement. Once the cuttings are back in the annulus, the annular velocity must be high enough to move the cuttings up the hole. The cutting bed height is approximately inversely proportional to the annular velocity. An increase in annular velocity improves hole cleaning regardless of the flow regime.

Sometimes “weighted sweeps” and pipe movement will assist in moving more of the cuttings up the hole. Low plastic viscosities are beneficial here because the fluid is more easily moved under the drillstring and the low-shear-rate viscosity is enhanced.

The cuttings bed that does form on the bottom of the wellbore may tend to form blockages as discontinuities in the drillstring profile plow solids in front. Stabilizers or changes in BHA profiles create surfaces that move solids into barriers as the BHA is moved up the hole. Pipe rotation and high circulation rates are needed to destroy these barriers and move the solids up the hole. This condition is accentuated when low places are created along the bottom part of the borehole. Cuttings tend to gather as the drill collars ride over the top of the cuttings bed. As the BHA is pulled from the borehole, these cuttings may be plowed up to create new barriers and stick the drillstring. Some locations are now circulating drilling fluid while tripping pipe to keep the solids from blocking the wellbore as the tool joints, stabilizers and bit are plowing solids which could block the hole during bit trips.

Elevated values of low-shear-rate viscosities are important in large diameter intervals. Solids are transported better when the 3 rpm and 6 rpm readings on a concentric cylinder

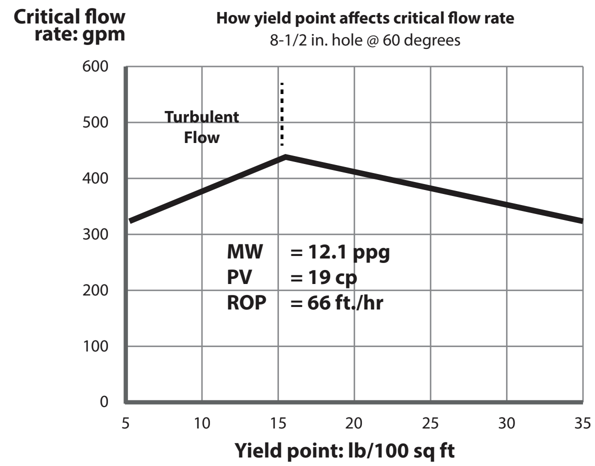


Figure 6-6: High-angle hole cleaning.

viscometer have values about the same as the hole size in inches. (This is a strange "rule-of-thumb" — but it seems to work.) If the plastic viscosity is kept low (by removing drilled solids from the drilling fluid), the low-shear-rate viscosity can be very effectively raised to a high value. A 3-rpm reading of 12 would indicate a 1,200-cp viscosity. High gel strengths are necessary to keep drilled solids in suspension when the pumps stop. (But here the gels cannot be progressive.)

High flow rates in the annulus will not "erode" the borehole. Field tests have shown that if nozzle shear rates with roller cone bits are less than 100,000 reciprocal seconds, the borehole will not enlarge.

Attempts to make the drilling fluid turbulent in the annulus are generally counterproductive. The drilling fluid low-shear-rate viscosity usually must be relatively low to allow for turbulent flow. This drilling fluid will not have suspension characteristics necessary to carry drilled solids through the almost vertical sections of the hole. When circulation stops, or where hole diameters increase in the higher angle part of the hole, cuttings will quickly fall to the bottom of the hole.

6.12 API discussion of cleaning high-angle wells

The model used in API RP 13D is based on the fluid forces acting on cuttings within a settled bed. The model takes into account both lift and drag forces to predict the minimum flow rate required to prevent formation of a stationary cuttings beds. The model was originally developed from flow loop data and has been validated against numerous high-angle and horizontal wells.

The main features of the model are:

- Allows for rheology and flow regime;
- Models washed-out hole;
- Assumes the drillpipe is rotated at 100 rpm;
- Predicts flow rate requirements with changing ROP.

The model developed from this study suggests that either thick or thin drilling fluids can be used to clean high-angle sections. Intermediate viscosity drilling fluid provide the worst conditions and should be avoided.

The hole cleaning recommendations in API RP 13D for high-angle and horizontal holes was developed by British Petroleum Corporation (BP) in the late 1980's and early 1990's. These recommendations were not based on observations of the shape of the cuttings on the shale shaker as was used to develop the CCI. In about 30 to 50 wells, records of over 100 section intervals were examined for direct and indirect symptoms of poor hole cleaning. Criteria were based on indications of tight hole, excessive drag forces while tripping out, unscheduled back-reaming, cuttings pack-off, and mechanically stuck pipe. In laboratory experiments the Buckingham Pi model was used to develop dimensionless groups to indicate problems. The results achieved while drilling seemed to verify these results. As a common practice, BP also now uses pressure while drilling (PWD) telemetry data to indicate whether cuttings are increasing in the annulus. PWD indicates the ECD and is responsive to increases in cuttings concentration.

This method, relies primarily on flow rate to clean the hole. For this reason, the intermediate values of yield points are avoided (Figure 6-6).

When turbulent flow is used to carry cuttings, the cuttings are obviously tumbled and become much smaller. The debris from this mechanism of hole cleaning increases the plastic viscosity of the drilling fluid and also makes many of these cuttings smaller than the shale shaker screen can remove.

Figure 6-6 shows how increasing the mud yield point causes the flow mechanism to change from turbulent to laminar. Intermediate values of YP should be avoided since they produce the worst conditions for cuttings transport. In general the higher YP (and hence laminar flow) regime is preferred because the higher low-shear-rate viscosities provide better cuttings suspension, less barite sag and improved transport in the near vertical regions of the well.

6.13 Analysis

Two different criteria were used to evaluate "hole cleaning" in vertical wells and in high-angle wells. The vertical hole cleaning equation predicts the appearance of cuttings arriving at the surface. Sharp edges indicate the cuttings have not been tumbled on their trip out of the hole. The high-angle hole cleaning was developed from analyzing "hole problems" and not from sharp-edge cuttings. Circulating a drilling fluid in turbulent flow should result in cuttings being ground into spheres. The detritus from this grinding will increase the concentration of small particles in the annulus and increase the plastic viscosity of the drilling fluid.

As a reminder, plastic viscosity should be as low as possible. Plastic viscosity controls the ability to remove cuttings from the bottom of a borehole. Drilling performance is a casualty of high plastic viscosity drilling fluids. High plastic viscosity values also decrease the carrying capacity of drilling fluid in the vertical part of a well.

Currently, some effort is being directed toward developing horizontal hole cleaning criteria using a viscoelastic model. Drilling fluids which seem to clean high-angle holes have a high elastic modulus. Much of the current effort is directed toward increasing the very low-shear-rate viscosity of a fluid. Solids will settle but more slowly. Hopefully, in a medium which looks like an elastic body to a settling drilled solid, the solids will not settle as they are being transported.

In a high-angle well, solids need to fall only a few inches to reach the bottom. In vertical wells, the settling distance is many feet. With simpler drilling fluid systems of many years ago, most drilling contractors subscribed to the concept that fluid velocity was the primary parameter that would prevent settling in pipes. For example, in the lower backflow lines between mud tanks, barite would settle if the velocity was less than 5 ft/sec. They tried to prevent the velocity from exceeding 10 ft/sec to prevent turbulent flow. The wisdom of that era was that velocity was the primary condition for transporting drilled solids. Fortunately, several thousand feet of horizontal hole can be cleaned with pipe rotation and adequate rheology. These techniques are still evolving because this causes the solids to grind into smaller pieces which increases the plastic viscosity and are difficult to remove.

Some interesting work is currently underway regarding the viscoelastic behavior of drilling fluids. The difference between a liquid and a solid seem rather clear from a superficial examination; consider, however, a salt dome. The salt is flowing upward from a deep layer and, frequently, even pushes the surface upward above the surrounding terrain. A salt core seems very solid; yet it flows. This is viscoelastic behavior. Obviously, the flow is very slow; consequently, the "viscosity" would be very high.

Many complex mixtures are described mathematically by relating the shear stress to the shear rate. These are the normal methods of describing the flow of a fluid. The mixture is said to be a Newtonian fluid if the shear stress is proportional to the shear rate. The constant of proportionality is called "viscosity". An elastic solid has a shear displacement directly proportional to the shear stress. Hooke's law describes these solids by stating that the strain is proportional to the stress.

Some materials, like salt, exhibit characteristics of both liquids and solids. If such a material is subjected to an oscillatory stress, the measured strain will not exactly be in-phase with the applied stress (like an elastic solid) or exactly out-of-phase with the applied stress (like a liquid). The measured strain would be some intermediate angle between 0-90°. So the material acts like a viscous material for part of the cycle and an elastic material for part of the cycle, creating the term "viscoelastic".

The rheological equation (Equation 6-12) which describes this behavior involves relating the shear stress (τ) to a complex shear relaxation modulus, G. The stress on the material under oscillation with a frequency of $\omega /2\pi$ with a maximum amplitude of shear rate (γ), could be represented with the equation:

$$\tau = \gamma \,(G' \sin \omega t + G'' \cos \omega t) \qquad \textbf{Equation 6-13}$$

Where:

- t is time
- G' is the shear, or elastic, modulus (the in-phase component)
- G" is the viscous modulus (the out-of-phase component)

Some preliminary work has indicated that drilling fluids with a high elastic modulus have been successful in cleaning horizontal holes. The application of this technology was difficult initially because the equipment used (a cone-and-plate viscometer) was very large and not suitable for deployment into field operations. Recently, Grace Instruments Company has modified a concentric cylinder viscometer to make both the normal rheology measurements (PV, YP, gels, etc.) and the viscoelastic moduli. Guidelines are not available yet to indicate the values of the elastic modulus which are needed to clean horizontal holes.

Horizontal holes can be cleaned effectively if drilled solids are prevented from falling through the drilling fluid. If a fluid does not have a reasonably large elastic modulus, solids will settle. For example, solids suspended in honey will slowly fall through the fluid; solids suspended in jelly will not fall. Why? Honey is a Newtonian fluid with a zero elastic modulus. Jelly has a very high elastic component and will suspend solids. The question has always been: "how do you produce a fluid that flows easily but has a very high, easily broken gel structure when flow ceases?" Two common ways have been developed for water-based drilling fluids: high concentrations of XC polymer and MMH (or MMO).

The development of the concept of critical polymer concentrations (CPC) has been effective in cleaning very high-angle holes. XC polymer has been used for many years because of the shear-thinning characteristic and has been used effectively to clean vertical wells. Powell, Parks and Seheult, in 1991, reported that increasing the concentration above 1.75 or 2 lb/bbl of XC to a CPC increased the G' (or the elastic modulus). They reported the benefits of high concentrations of XC in drilling fluids compared with conventional fluids to be:

- Pump pressures were lower for the same flow rates;
- Circulation lag time was reduced;
- Torque and drag were reduced due to improved hole cleaning;
- Fewer problems running logging tools, casing, or liners.

Another development was the use of mixed metal hydroxides (MMH) fluid. MMH is a highly positively charged man-made additive that creates some unusual fluid properties. A MMH drilling fluid in an East Texas well had a funnel viscosity of 45 seconds, yet it would support a 2-in. diameter rock on the surface of the fluid in a mud cup. The turnkey contractor claimed they were sinking record wells in the field because of better hole cleaning. The tool pusher on location sounded like a mud product salesman when discussing the benefits of cleaning the hole. The same gel structure created with bentonite would have required great pressure to break circulation. The additive is very sensitive to treatment on the surface and requires a very competent mud engineer to effectively use the product.

The point is that the viscous models are not working to help predict the properties needed to clean horizontal holes. The trend is to go to lower and lower shear rates to better describe solids moving slowly through the medium. This does not seem to be the total solution.

Appendix 6A: Graphical values of annular velocity

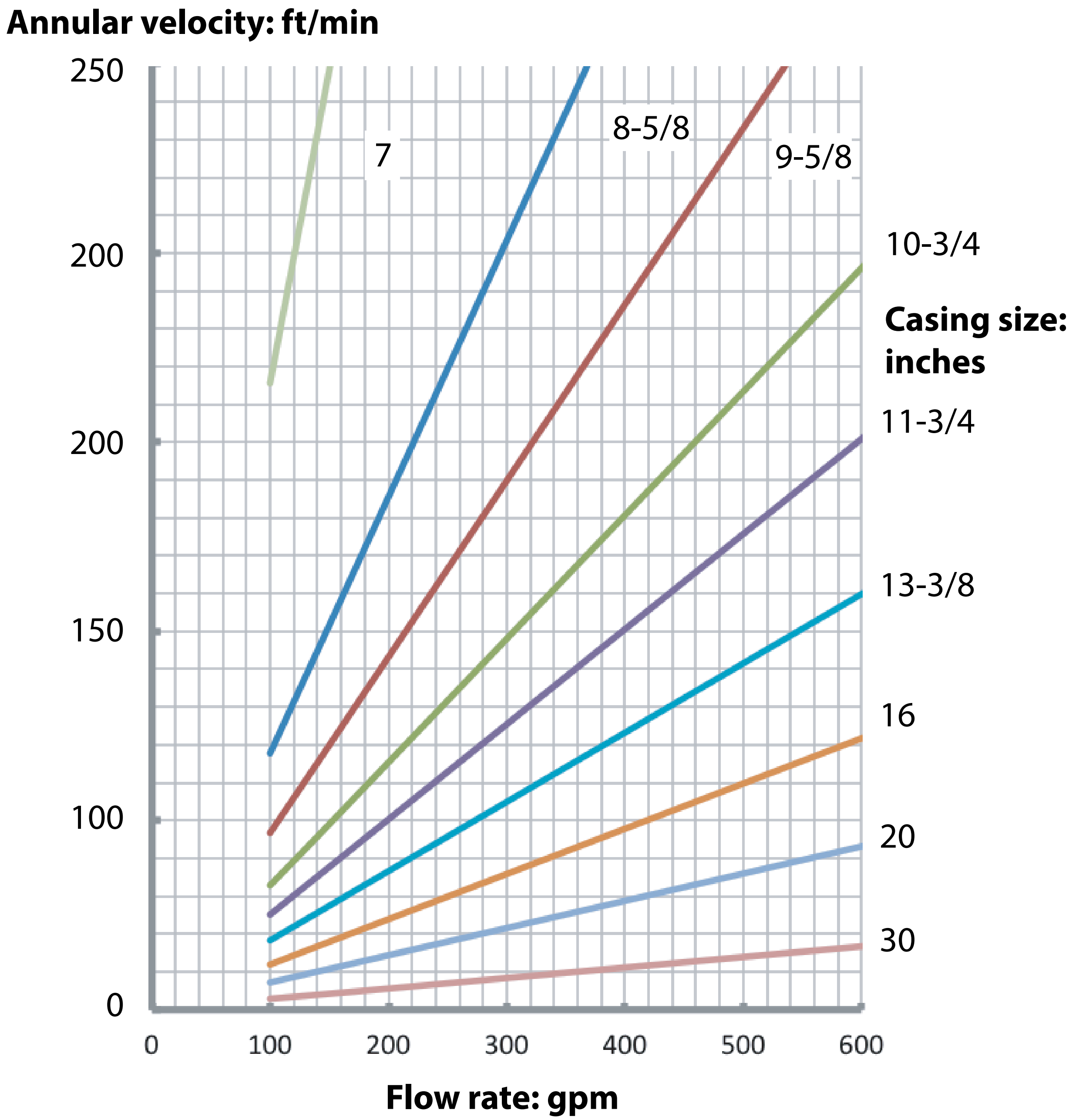


Figure 6A-1: Annular velocity for 4 ½-in. drillpipe. Annular velocity is 0-250 ft/min.

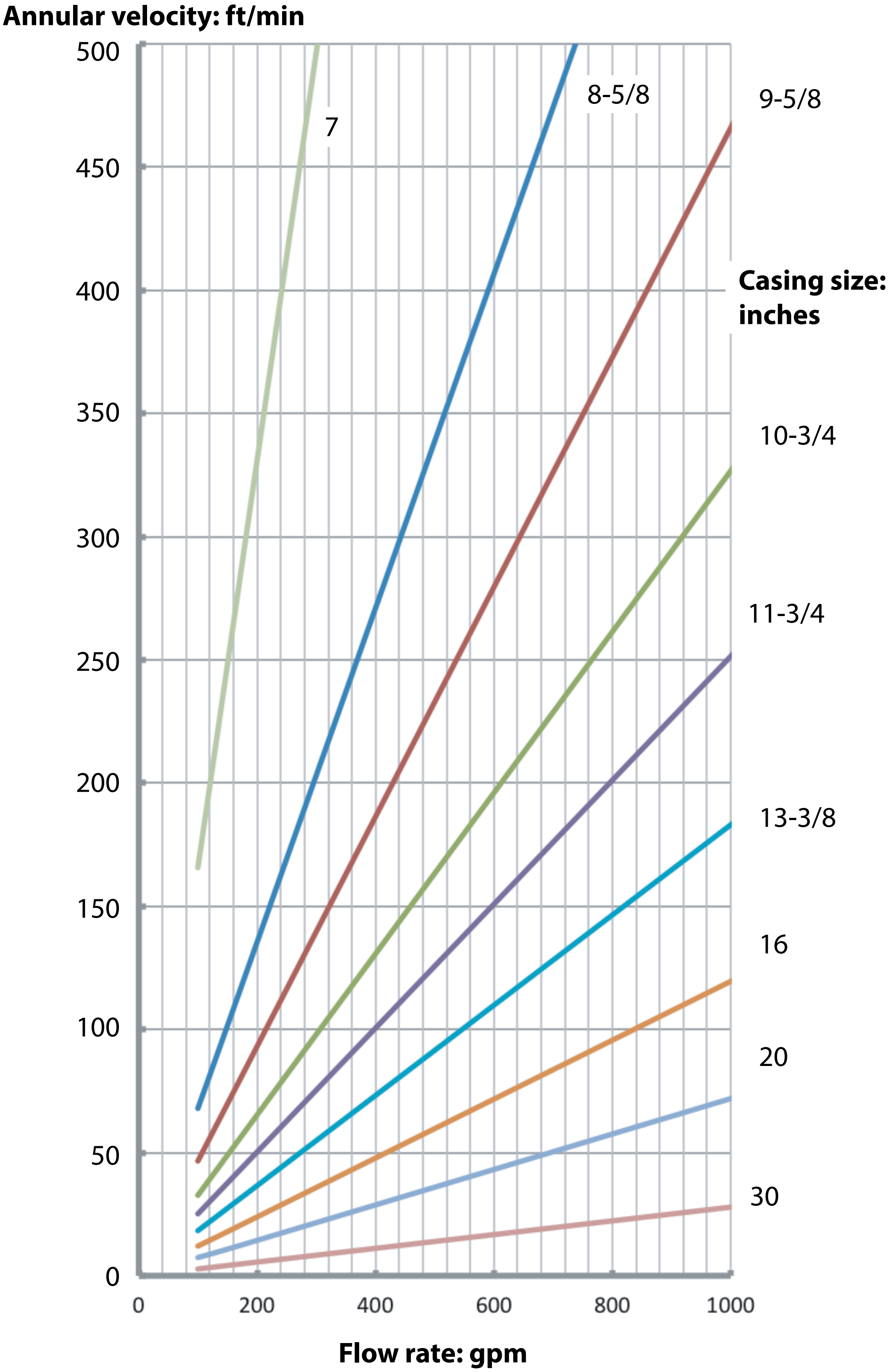


Figure 6A-2: Annular velocity for 4 ½-in. drillpipe. Annular velocity is 0-500 ft/min.

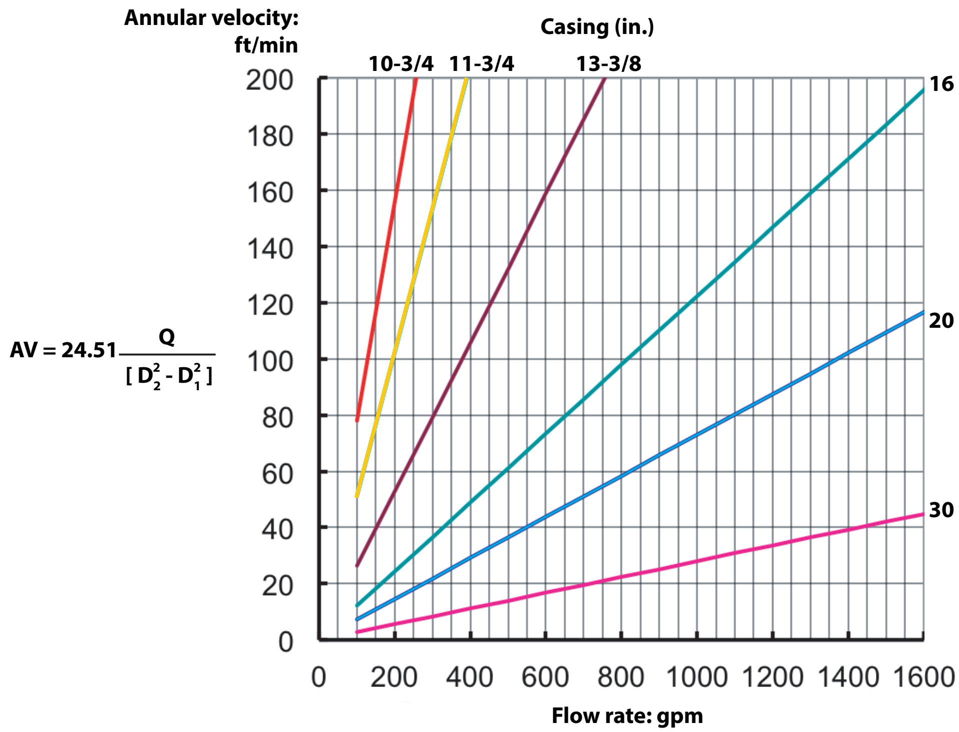


Figure 6A-3: Annular velocity for 5-in. drillpipe. Annular velocity is 0-200 ft/min.

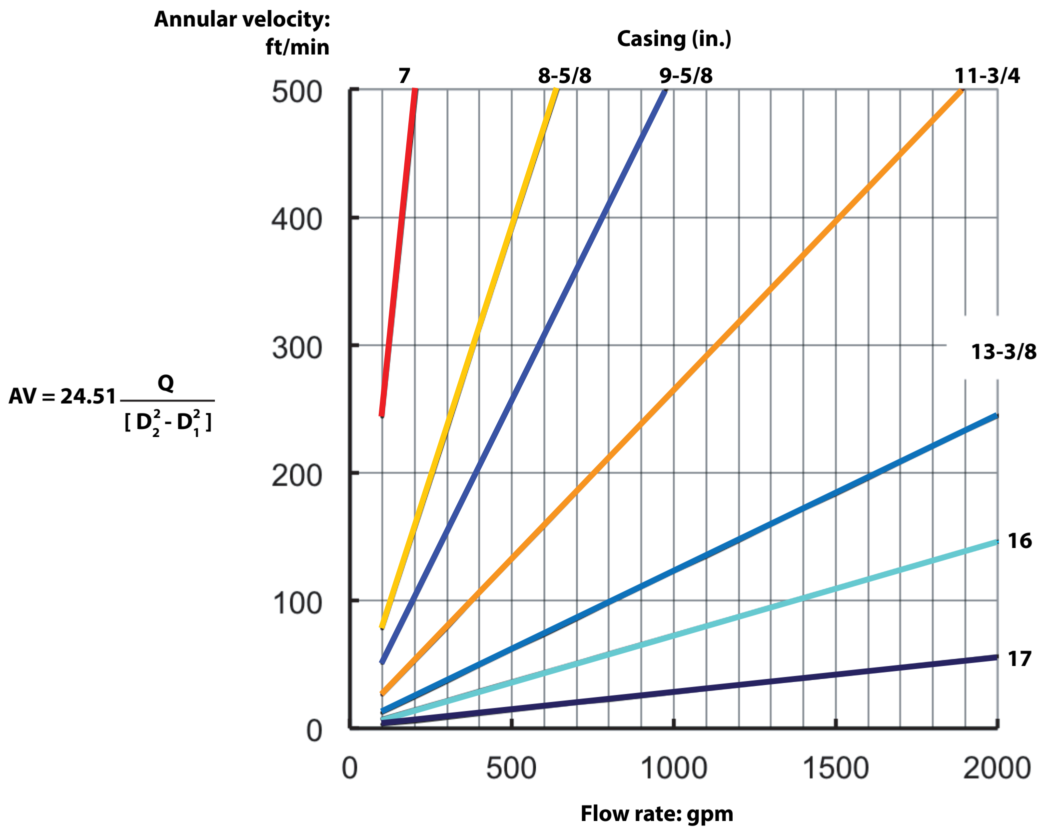


Figure 6A-4: Annular velocity for 5-in. drillpipe. Annular velocity is 0-500 ft/min.

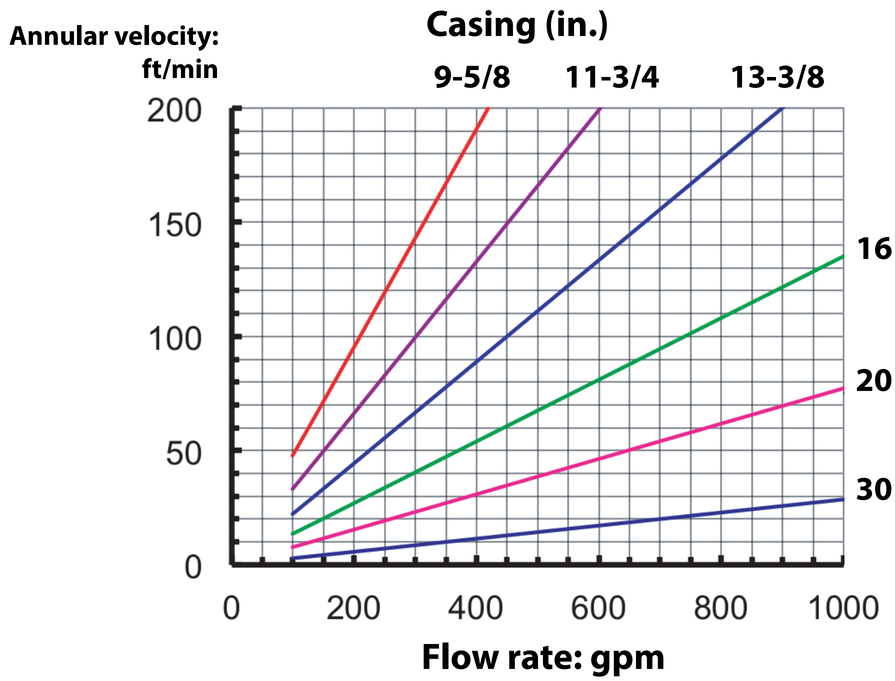


Figure 6A-5: Annular velocity for 6 ⅝-in. drillpipe. Annular velocity is 0-200 ft/min.

Appendix 6B: Viscoelastic measurements

The rheological equation which describes this behavior involves relating the shear stress, τ, to a complex shear relaxation modulus, G. The stress (τ) on the material under oscillation with a frequency of ω/2π with a maximum amplitude of shear rate (γ), could be represented with the equation:

$$\tau = \gamma\,(G' \sin \omega t + G'' \cos \omega t) \qquad \text{Equation 6B-1}$$

Where:

- t is time
- G' is the shear, or elastic, modulus (the in-phase component)
- G" is the viscous modulus (the out-of-phase component)

Some preliminary work has indicated that drilling fluids with a high elastic modulus have been successful in cleaning horizontal holes. The application of this technology was difficult initially because the equipment used (a cone-and-plate viscometer) was very large and not suitable for deployment into field operations. At least one concentric cylinder viscometer is now available to make both the normal rheology measurements (PV, YP, gels, etc.) and the viscoelastic moduli. Guidelines are not available yet to indicate the values of the elastic modulus which are needed to clean horizontal holes.

The point is that the viscous models are not working to help predict the properties needed to clean horizontal holes. The trend is to go to lower and lower shear rates to better describe solids moving slowly through the media. This does not seem to be the total solution.

Figure 6B-1: Model M5600 HPHT Rheometer. Courtesy Grace Instrument Co.

Appendix 6C: Problems in carrying capacity

Table 6C-1: Problem 1, Part 1 worksheet.							
Fluid Number	AV ft/min	MW ppg	PV cp.	YP lb/100 sq ft	n	K eff.cp.	CCI.
1	60	9	5	5			
2	60	9	5	10			
3	60	9	5	12			
4	60	9	5	15			
5	60	9	10	5			
6	60	9	10	10			
7	60	9	10	15			
8	60	9	10	17			
9	60	9	10	20			
10	60	9	16	10			
11	60	9	16	15			
12	60	9	16	20			
13	60	11	8	10			
14	60	11	8	15			
15	60	11	8	20			
16	60	11	14	10			
17	60	11	14	15			
18	60	11	14	17			
19	60	11	14	20			
20	60	15	15	10			
21	60	15	15	15			

Table 6C-2: Problem 1, Part 2 worksheet.			
Fluid Number	AV ft/min	MW ppg	K needed
1	60	9	
2	60	9	
3	60	9	
4	60	9	
5	60	9	
6	60	9	
7	60	9	
8	60	9	
9	60	9	
10	60	9	
11	60	9	
12	60	9	
13	60	11	
14	60	11	
15	60	11	
16	60	11	
17	60	11	
18	60	11	
19	60	11	
20	60	15	
21	60	15	
22	60	15	
23	60	15	

Problem 1: Carrying capacity exercise

Part 1

The lowest annular velocity for the well is 60 ft/min. For the drilling fluid properties listed in Table 6C-1, determine which wells will have a problem with hole cleaning.

Part 2

The yield point of a drilling fluid can be changed without a significant change in the PV. What should be the K value be to make certain that all drilling fluids are cleaning the borehole? (Refer to Table 6C-2.)

Sample calculation

K = 400,000 / (MW, ppg) (AV, ft/min)

From the K value graph (Figure 6-1), read the YP needed.

Problem 2: Carrying capacity

An 11.0 ppg water-based PHPA drilling fluid was being used to drill a 9 ⅞-in. hole below an 11 ¾-in. casing. The circulation rate was 550 gpm down the 4 ½-in. drillpipe (annular velocity 134 ft/min). The drilling fluid properties have been deteriorating slowly during the past week. The plastic viscosity has been slowly increasing from 11-22 cp; the yield point was held constant at 11 lb/100 sq ft. and the solids content has increased from 13% vol. to 19% vol. The filter cake quality was continually decreasing.

As this trend started, Joe Stumpem was diligently plotting the variable and had several conversations with the drilling foreman, Heizen Schwanz. They slowly increased the yield point of the drilling fluid from 11 to 15 lb/100 sq ft. At the same time the gels increased from 4/10 to 9/20. To take full advantage of their linear motion shakers, the screens were changed from an API 120 to an API 200 screen. During the week, the change in drilling fluid properties required that the end of the shaker be elevated eventually to the maximum height possible to prevent loss of drilling fluid from the end of the shaker. The derrickman was instructed to thoroughly examine the shaker screens for holes or rips. The mounting of the screens on the decks were evaluated for leaks between shaker and the screens. The mud cleaner was inspected. No mechanical problems could be located which would explain the rise in drilled solids during this interval of the well. Other wells in the field, using different mud systems, had drilled this interval without the increase in drilled solids and generally only 100 mesh screens had been used by offset operators.

Ineffective hole cleaning could account for the symptoms plaguing this rig. The cuttings coming from the shale shaker were cubic pieces of shale about 1⁄16 in. on each side. Small cuttings normally mean that the hole is not being cleaned; although in this case the edges of the cutting were sharp not rounded. Poor hole cleaning causes cutting to tumble in the hole and rounds the edges of the cuttings. The Carrying Capacity Index (described in PEI, Sept. 1993) in the largest annulus was initially above 1.0 (PV 11, YP 11, (K = 293), (AV 134, MW 11). When Joe arrived at the rig, he increased properties (PV 11, YP 15, (K = 284) to return the CCI to a value above 1.0.

What should be done? Maybe the CCI doesn't help in this situation. Or do they need a centrifuge, another linear motion shaker, or some other equipment?

Problem 3

You arrive at a drilling rig and the toolpusher greets you with enthusiasm and asks that you to immediately go to the rig floor. He and the driller have had some serious discussions about the situation. They are observing the classic symptoms of a problem they have encountered many times. In this case, they have not been able to get the office drilling group to listen to their recommendations.

The rig is drilling at 11,200 ft with a 14 ¾-in. bit, IADC Code 127. The 16-in. surface casing was set deep, 4,000 ft, because this well will be exploring formations below current production. They have 5-in. drillpipe and the bottom five collars are 10 in. diameter. The drilling fluid properties are reported to be: mud weight 11 ppg, PV 20 cp, YP 10 lb/100 sq ft, gels 10/30, pH 10.0, funnel visc 52 sec. The flow rate is 800 gpm. The toolpusher points out that he was told to increase the viscosity of the fluid to help bring the cuttings out, so he has allowed the PV to go to 20 cp. He also has some friends who are selling him "hole slickeners" at $200/drum and he is adding two of those per tour. He is keeping the yield point to a modest value of 10 so it will be easier to pump the fluid down the hole and blend it in the mud tanks.

They want you to watch a connection and see the drag on the pipe when the pump is off. The driller says it feels like the shale is closing in around the bit. The toolpusher and driller say that this is a common occurrence in this area and they have seen it many times. Turning on the pumps applies pressure to the bottom of the hole and opens the hole up. This, they report, only cures the problem for a short period of time and then they must increase the mud weight to continue to be able to make connections. When they reported this to the office, they claimed that the weevil operations people thought it might be a hole cleaning problem. From the rig floor, the cuttings could be observed so deep on the shaker that it was hard to see the shaker screen, so they did not believe this explanation.

In their experience, this situation will get worse unless several things are done immediately. They want to trip out of the hole and remove those large drill collars before the shale squeezes in around them so they can't move the pipe. They say this happens all the time to people not heeding their warning. They want to increase the mud weight to 13-14 ppg. They admit that the morning report shows an 11 ppg drilling fluid, but it actually weighs 12.0 ppg. They say they were trying to help the inexperienced people in the office by increasing the mud weight, but they can't go much higher before the barite use reveals what they are doing. In their experience, the shale will finally squeeze in around the bit so they can't even pump. Then, after a connection, when they turn on the pumps, they will lose circulation. The liquid level in the annulus will drop and the well will start flowing. Closing the well in will guarantee stuck pipe and this disaster will require about a month to correct. They also say that the shale that creeps into the wellbore gets harder and harder. They already see this as proof because the drilling rate has dropped from 50 ft/hr to 30 ft/hr. After they increase the mud weight to hold the shale back, they expect to be drilling about 5-8 ft/hr. All the symptoms are there and they encourage you to act now before it becomes too late.

Are you going to trip the bit and remove the big drill collars before increasing the mud weight? Do you increase the mud weight before the trip? Are you going to agree with these seasoned professionals who have seen this series of events many times in this drilling area? What are you going to do?

To help sort through these suggestions: First, what do the cuttings look like on the shaker screen?

Answers:

Table 6C-3: Answers for Problem 1, Part 1.						
AV ft/min	MW ppg	PV cp.	YP lb/100sqft	n	K eff.cp.	CCI.
60	9	5	5	0.58	133	0.18
60	9	5	10	0.42	576	0.78
60	9	5	12	0.37	854	1.15
60	9	5	15	0.32	1373	1.85
60	9	10	5	0.74	77	0.10
60	9	10	10	0.58	266	0.36
60	9	10	15	0.49	619	0.84
60	9	10	17	0.45	810	1.09
60	9	10	20	0.42	1152	1.56
60	9	16	10	0.69	178	0.24
60	9	16	15	0.60	375	0.51
60	9	16	20	0.53	673	0.91
60	11	8	10	0.53	336	0.55
60	11	8	15	0.43	801	1.32
60	11	8	20	0.36	1491	2.46
60	11	14	10	0.66	196	0.32
60	11	14	15	0.57	428	0.71
60	11	14	17	0.54	554	0.91
60	11	14	20	0.50	781	1.29
60	15	15	10	0.68	186	0.42
60	15	15	15	0.58	399	0.90
60	15	25	15	0.70	259	0.58
60	15	25	20	0.64	432	0.97

Table 6C-4: Answers for Problem 1, Part 2.			
Fluid Number	AV ft/min	MW ppg	K needed
1	60	9	741
2	60	9	741
3	60	9	741
4	60	9	741
5	60	9	741
6	60	9	741
7	60	9	741
8	60	9	741
9	60	9	741
10	60	9	741
11	60	9	741
12	60	9	741
13	60	11	606
14	60	11	606
15	60	11	606
16	60	11	606
17	60	11	606
18	60	11	606
19	60	11	606
20	60	15	444
21	60	15	444
22	60	15	444
23	60	15	444

Problem 1: Solutions

Part 1: See Table 6C-3

Part 2: See Table 6C-4

The yield point of a drilling fluid can be changed without a significant change in the PV. What should be the K value be to make certain that all drilling fluids are cleaning the borehole?

Problem 2: Solutions

The key to this problem was the statement:

"During the week, the change in drilling fluid properties required that the end of the shaker be elevated eventually to the maximum height possible to prevent loss of drilling fluid from the end of the shaker."

When this happened on a rig, the increase in solids was a big puzzle. The problem was solved by observing the shaker screen during a connection. After all the liquid drained through the screen, large cuttings had been hiding beneath the surface of the pool of liquid in the back section of the shaker screens. The high angle prevented these large cuttings from being transported out of the pool until the screen had broken them into small pieces. The shaker screens were replaced with API 100 screens for one circulation. The deck angle was lowered so that cuttings could be transported out of the liquid pool. A large number of cuttings were removed and the PV decreased significantly. The API 100 screens were changed again to API 150 screens and, eventually, to API 200 screens with a lower deck angle. After each circulation, the PV decreased and the YP could be lowered.

Problem 3: Solution

To the driller, the symptoms definitely felt like the shale was squeezing in around the bit and drill collars. However, the problem with this analysis is that caliper logs have not found 10 feet of undergauge shale in any well. Shale does not flow into a wellbore. Salt will flow into a wellbore but not shale. The problem is that the cuttings were tumbling in the annulus and being suspended by the flowing drilling fluid. The cuttings will eventually arrive at the surface and even seem to bury the shale shaker screen. In a vertical hole, a high viscosity sweep would have brought a very large quantity of 'old' drilled cuttings to the surface. The CCI value on this well would have exposed the problem quickly.

Decreasing the drill collar diameter in a case like this would have been disastrous. To prevent the wellbore from "walking" or drilling a spiral hole, the drill collars need to be large – and then tapered back to the diameter of the drillpipe. Small drill collars in a large hole will soon bring grief because of pin breakage along with a wellbore that may not have sufficient drift diameter to allow the casing to reach bottom.

References

1. Williams, C.C. and Bruce, G.H. "Carrying Capacity of Drilling Muds", Trans AIME (1951) 189, 111-120.
2. Zeidler, U. "Fluid and Drilled Particle Dynamics Related to Drilling Mud Carrying Capacity" PhD Dissertation, University of Tulsa, Tulsa, Oklahoma, (1974).
3. Peden, J.M. and Luo, Yuejin "Settling Velocity of Variously Shaped Particles in Drilling and Fracturing Fluids" SPEDE (Dec 1987) 337-343.
4. Bizanti, M.S. and Robinson, S. "Transport Ratio Can Show Mud-Carrying Capacity", Oil and Gas J. (June 1988), 39, 43-46.
5. Bizanti, M.S. and Robinson, S. "PC Program Speeds Slip Velocity Calculations", Oil and Gas J. (Nov 1988), 44-46.
6. Lyoho, A.W.,Horeth, J.M., and Veenkant, R.L. "A Computer Model for Hole-Cleaning Analysis" JPT (Sept. 1988) 1183-1192.
7. Chin, W.C. "Exact Cuttings Transport Correlations Developed for High Angle Wells" Offshore Magazine (May 1990) 67-70.
8. Gavignet, A.A. and Sobey, I.J. "Model Aids Cuttings Transport Prediction" JPT (Sept 1988) 916-921.
9. Uner, D., Ozgen, C., and Tosun, I. "Flow of a Power-Law Fluid in an Eccentric Annulus" SPEDE (Sept 1989) 269-272.
10. Chin, W.C. "Advances in Annular Borehole Modeling", Offshore Mag (Feb 1990), 31-37.
11. Haciislamoglu, M and Langlinais, J. "Discussion of Flow of a Power-Law Fluid in an Eccentric Annulus" SPEDE (March 1990) 95
12. Sifferman, T.R. and Becker, T.E., "Hole Cleaning in Full-Scale Inclined Wellbores" SPEDE (June 1992), 115-120.
13. Sifferman, T.R., Myers, G.M., Haden, E. L., and Wahl, H.A. "Drill-Cutting Transport in Full-Scale Vertical Annuli", JPT, (Nov 1974), 1295-1302.
14. Williams, C.C. and Bruce, G.H. "Carrying Capacity of Drilling Muds", Trans AIME (1951) 189, 111-120.
15. Zeidler, U. "Fluid and Drilled Particle Dynamics Related to Drilling Mud Carrying Capacity" PhD Dissertation, University of Tulsa, Tulsa, Oklahoma, (1974).
16. Peden, J.M. and Luo, Yuejin "Settling Velocity of Variously Shaped Particles in Drilling and Fracturing Fluids" SPEDE (Dec 1987) 337-343.
17. Bizanti, M.S. and Robinson, S. "Transport Ratio Can Show Mud-Carrying Capacity", Oil and Gas J. (June 1988), 39, 43-46.

Chapter 7
Mud Logger Operations

TABLE OF CONTENTS

7.1 INTRODUCTION

A mud logger measures many things around a drilling rig and provides valuable information. One of the more important measurements consists of a measurement of gas in the drilling fluid. As the drill bit grinds rock at the bottom of a borehole, the gas contained in the rock is released into the drilling fluid. When a bit is raised from the bottom of a borehole, for example, to make a connection, the swab pressure will frequently allow gas to enter from the formations near the drill bit. The quantity of gas that enters is obviously a function of the permeability of the formation and the pressure differential created by the swab pressure. Since the driller raises the drillpipe at almost the same speed, the swab pressure remains relatively close to the same value. (Shale's permeability is relatively low and it is the most common rock drilled.). If the volume of gas entering the wellbore seems to be increasing with every connection, the mud weight in the borehole probably needs to be increased. If the drill bit is moved passed a more permeable rock, the same swab pressures will cause more gas to enter the well during a connection. However, since shale is the predominant rock drilled, most connection gasses will come from the shale and the volumes compared from one connection to the next.

To determine the gas in a drilling fluid that is returning from the bottom of the hole, a gas trap is mounted in the back tank of the shale shaker. A small pump or stirrer circulates drilling fluid from the back tank through the gas trap. A space above the liquid (Figure 7-1) is connected with a small hose to a vacuum system in the mud logger's equipment. Any gas contained in the drilling fluid is liberated and travels through the hose to a detection device and usually a chromatograph. The gas volume is measured and is recorded on a graph as a function of time.

The area under a mud logger's gas unit curve is proportional to the volume of gas in a drilling fluid. Even though this has been published as early as the 1950s, most morning reports only record the maximum readings for connections or after bit trips.

The mud logger can measure combustible gas and usually also run the gas sample through a chromatograph to determine the various hydrocarbons present in the gas influx.

7.2 Volume of gas detected by mud logger

The mud logger continuously measures the gas arriving at the surface while circulating drilling fluid. The background gas comes from formation material ground by the drill bits as well as from ledges along the borehole walls. Background gas can be very low if the borehole is smooth, the rock has very little gas, or the gas-bearing sand is very permeable (filtration ahead of the bit may move the gas away from the cuttings). Background gas can be very high if the formations

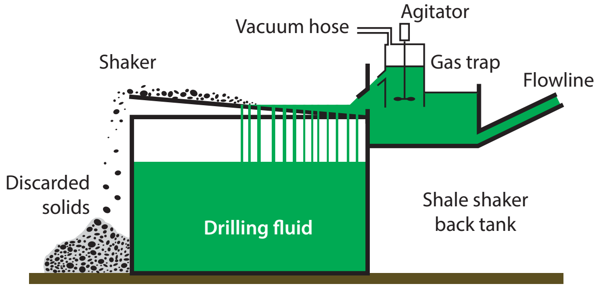


Figure 7-1: Mud logger gas trap in shale shaker back tank.

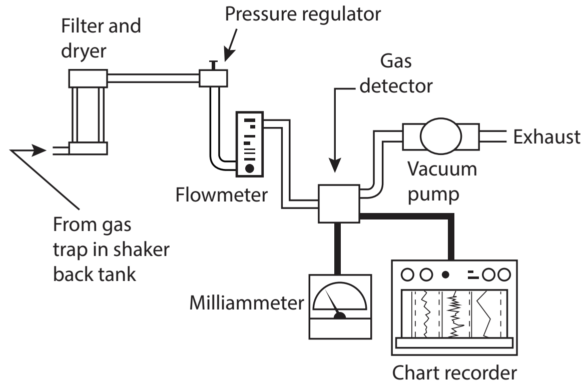


Figure 7-2: Mud logger gas detection equipment arrangement.

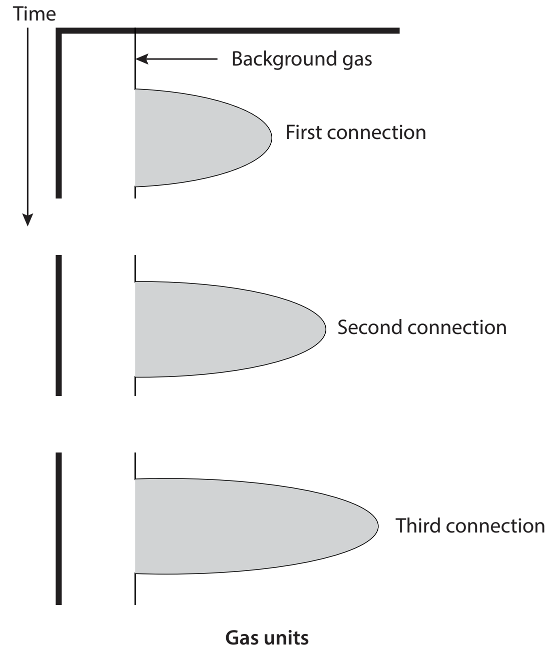


Figure 7-3: Stylized gas unit curves.

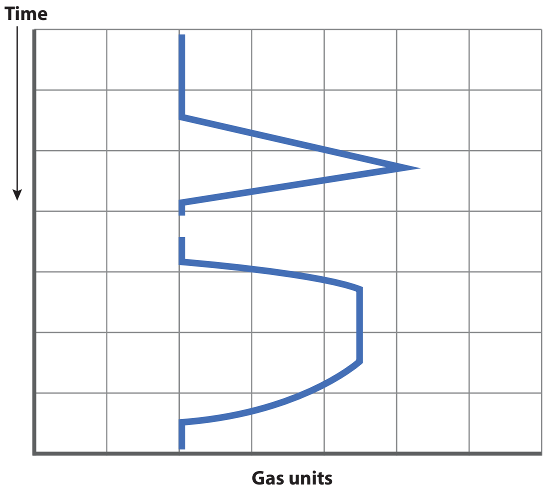


Figure 7-4: Area under curve indicates volume of gas, NOT the maximum reading.

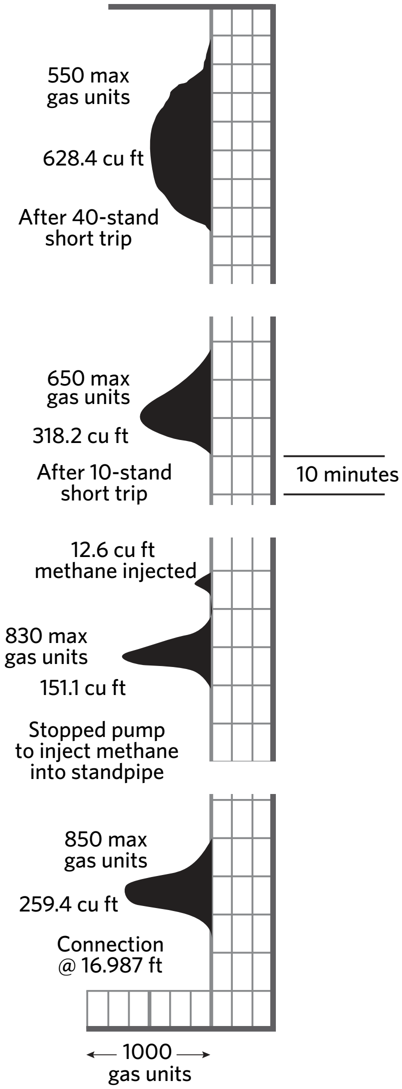


Figure 7-5: Field example of misinterpretation.

being drilled contain a lot of gas and the wellbore has many ledges. A high background gas does not indicate the potential for a kick. The quantity of gas swabbed into a borehole when making a connection is represented by the area under the gas unit minute curve — not the maximum reading.

In Figure 7-3, which shows connection gas, the volume of gas arriving at the surface is larger with each connection. The area under the curve (the shaded area) is larger with each connection. This indicates that the wellbore pressure is getting closer to the formation fluid pressure. The mud weight was being increased in anticipation of drilling into abnormal pressure.

In Figure 7-4, the morning report would show very high connection gas in the first connection (the one at the top of the chart). A lower gas unit reading would be indicated in the lower part of the chart. Much more gas was contained in the lower chart than in the upper. The volume of gas depends upon the area under the curve.

Figure 7-5 is a sketch of the mud logger's gas unit curve (MLGUC). Time starts at the bottom of the chart. A known volume of methane, from a small pressurized lecture bottle, was injected into the standpipe. By measuring the area under the curve when the combustible gas arrived at the surface, a constant can be developed to convert any gas bubble into a volume of gas. The gas peak which arrived at the surface from the methane injection was much smaller than the gas volume arriving from connection. The first peak shown on the time scale is from a connection. Drilling rate was slow, so the calibration gas was injected into the standpipe before a connection needed to be made.

Suspecting that they were approaching abnormal pressure (from the connection gas shown as the two lower peaks in Figure 7-5), the company man made a 10-stand short trip. The maximum gas unit after returning to bottom was lower than the connection gas units. He was still not really satisfied, so a 40-stand short trip was made. The maximum gas units, as shown in the top section of the chart, were lower than the 10 stand trip maximum gas units. Based upon the maximum readings, the rig started out of the hole. About halfway out, the well started flowing. Basing the gas influx on the maximum chart reading instead of the area under the gas-unit curve was grossly incorrect. To kill a kick, the bit must be placed on bottom and the kick circulated out. Stripping back to bottom takes a long time. This was wasted time because of a lack of understanding of the gas unit curve.

Other interesting features about Figure 7-5 are the second and third gas unit peaks from the bottom. Some are reluctant to inject gas into the standpipe because it might "induce a kick". On this chart, the injected gas formed a very small blip on the mud logger's gas unit curve. To inject a small amount of methane, the pump was stopped for a short time as the gas was injected. The small peak is the calibration gas that arrived after the larger volume of gas which entered the wellbore while the pumps were shut off. This shows that the ECD was preventing the well from flowing. A significant amount of gas entered the wellbore when the pumps were stopped. Clearly, additional mud weight was needed before making a trip.

7.3 Mud logger calibration

The mud logger gas unit curves (MLGUC) all seem to have different sensitivities and their values have long been an enigma to drillers. While drilling the same formations with the same mud weight, different mud loggers will report significantly different values of gas units. Of course, some of the problems are the sensitivity of the gas trap, and its location in the mud stream significantly affects the readings. The MLGUC can be calibrated so that the volume of gas influx can be determined.

7.3.1 Procedure to calibrate a mud logger gas unit

After a connection, inject a small amount of methane into the standpipe. Injection is easier when the pipe or kelly is drained before the methane is injected. The methane is bled from a small pressurized bottle. Measure the pressure in the bottle before and after the injection. During the injection, the bottle will cool. Volume calculations may be corrected for temperature or the final pressure measurements can wait until the bottle warms to the original temperature. From conventional gas behavior equations, the change in pressure of a known volume (the bottle) of gas reveals the volume of gas injected into the standpipe. This volume can be calculated on the basis of rig floor temperature or standard conditions.

After the methane is injected into the standpipe, drilling can resume. The methane will pass through the drillstring and through the drill bit nozzles and be dispersed in almost the same manner as an influx of gas.

About 15 to 20 minutes before the injected methane reaches the drill bit, cease drilling to avoid contaminating the injected methane with drill gas. Resume drilling about 15-20 minutes after the methane has passed the bit. This procedure allows the MLGUC to reach a level background reading before and after the methane reaches the gas detector. Obviously this method works better if the well is relatively deep and the wellbore pressure is higher than the formation pressure.

When the methane reaches the surface, the driller should not make a connection or turn the pumps off until after the MLGUC has completed the methane peak and the gas units return to the background value. The area under the peak, omitting the background area, is counted in gas-units-minutes (GUM). An easy way to determine the area under the curve is to record the gas unit value every minute when the gas starts arriving at the surface. Add all of these values until the gas unit values return to the back ground value and subtract the area associated with the background base.

Dividing the volume of injected methane by the area under the MLGUC results in a constant that is specific for this rig. This constant can be verified by injecting a different volume of methane and repeating the process. The constant will change if the gas trap is moved, or if the fluid rheology changes significantly or if there is a significant change in the flow pattern through the back tank on the shale shaker. The calibration constant, GUM/cu ft of methane, remains constant for long periods of time -- up to at least 10 days.

With the calibration constant, the volume of gas entering a wellbore during a connection or after a short trip can be calculated. This allows comparison between various mud logging units that may be operating in a particular area.

Calcium carbide, normally used for the mud logger's lag time, could be used if the formations are relatively tight. From the weight of the carbide lag, the volume of acetylene generated may be computed. At depths, in weighted mud, the acetylene becomes liquid and has a tendency to disappear into the formation through filtration. This is the reason some mud loggers "lose their lags."

7.4 Determining pore pressure

Information about formation pore pressure is desirable while drilling. The formation pore pressure is usually overbalanced during drilling to prevent formation fluid influx into the wellbore and prevent a kick or blowout. Excessive overbalance, however, significantly decreases the drilling rate and can also result in lost circulation. A technique has been developed to determine the overbalance (or underbalance) pressure at the bottom of the borehole while drilling. The technique relies upon the little known, but well established, fact that the area under a mud logger's gas unit curve is proportional to the volume of gas in the drilling fluid.

7.4.1 Technique

Stop drilling;

With the bit near bottom, pump drilling fluid long enough to move any drilled gas several hundred feet from the bottom of the borehole;

With the pumps off, raise the drillpipe at a constant speed from the bottom of the hole. Some gas will generally be swabbed into the borehole;

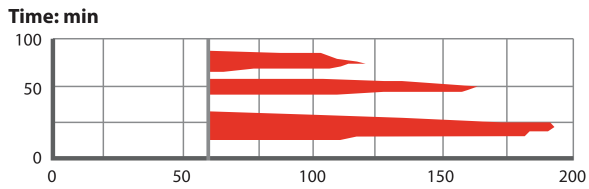


Figure 7-6: History of gas units from swab tests.

- Lower the drillpipe to the bottom and pump the gas bubble up the hole far enough to prevent overlapping of the next swabbed gas bubble;
- Repeat this procedure at least twice more while raising the drillpipe at different speeds.

After all of the gas bubbles have moved up the hole several hundred feet, drilling can resume while pumping the gas bubble to the surface. When the gas bubbles arrive at the surface, do not stop the pumps until all of the gas bubbles have been recorded by the mud logger (i.e., do not make a connection in the middle of the gas arrival at the surface).

7.4.2 Gas units

The mud logger measures the area under the curve for each gas bubble and subtracts the area created by the background gas. This calculated area is directly proportional to the volume of gas swabbed into the wellbore. The volume of gas that enters the wellbore is controlled by the pressure differential, formation permeability, porosity, gas saturation, and a number of other parameters. The only variable parameter at the time of the swab procedures is the pressure differential. The calculated areas represent the volume of gas swabbed into the wellbore by each pipe manipulation. The sketch of the history of gas units from a swab test is shown below:

The area would be calculated by counting the gas-units-minute (GUM) squares under the curve. The area is counted as that above the background of 60 gas units.

7.5 Swab pressures

Swab pressures can be measured downhole with pressure while drilling (PWD) tools if they record the data while the pump is not circulating drilling fluid. Most PWD telemetry systems require circulation to transmit data from the sensor packages. Recorders are available, however, which will store the pressure history and then send it to the surface when circulation is resumed.

The volume of gas arriving at the surface (or more precisely, the calculated area under the mud logger's gas unit curve) is plotted as a function of the swab pressure that created the gas bubble (Figure 7-7). If the swab pressure exactly matches the overbalance between the formation pore pressure and

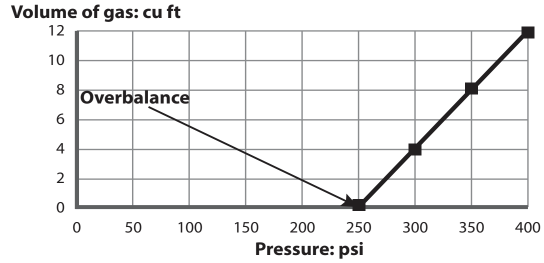


Figure 7-7: Extrapolation indicates the swab pressure that would be needed to allow gas to enter the wellbore. This is the overbalance at the bottom of the hole.

the bottomhole pressure, no gas would enter the wellbore. This pressure can be determined graphically by extrapolating the curve to the abscissa. The pressure value at the intercept would be the overbalance (or underbalance) that exists at the time of the swab tests. The sum of the bottomhole pressure [calculated, in psi, from the equation:

$$P = [0.052(MW) (Depth)]$$

The graphically determined overbalance is the formation pore pressure.

Caution: The PWD tools measure pressure in the annulus above the drill bit. Some indications from field observations indicate that the pressure beneath the bit may be substantially lower than the swab pressure in the annulus just above the bit. Drilling with an IADC bit code 137, 9 ⅞-in. bit in a 10.5-ppg drilling fluid through a gas sand, the connection gas was quite high. After drilling another single down, the connection gas was low. After drilling the next single down, the driller removed two joints from the drillstring and "pretended" to make another connection. In this case, the gas units duplicated the high value. The pressure decrease below the drill bit was sufficient to swab more gas into the well, rather than simply moving the drill collars up the hole. Apparently, there is a reasonably large pressure drop across the drill bit as it moves up the hole. The opportunity to install a center jet pressure measuring device was never available. Comparing the pressure in the annulus with a PWD tool and the pressure measured through a center jet position would be an interesting exercise to quantify the pressure drop created by only the bit as it moves up or down in the well.

If PWD tools are not available, the swab pressure can still determined, but with more effort. Swab pressures cannot be measured at the surface. Surge pressures can be measured at the surface just as the shut-in pressures are observed in a well control situation. Surge pressures, however, cannot be measured at the standpipe but must be measured below a valve in the drillpipe. A calibration chart is generated by measuring the surge pressures at the surface while lowering the drillstring at various speeds. The pipe speeds should overlap those used in the swab tests described above. Since the surge and swab pressures have the same values for the same pipe speeds, the calibration charts can be used to determine swab pressures.

A modification must be made to the drillstring at the surface to properly measure the surge pressures. When the mud pump is turned off, the drilling fluid in the pipe at the rig floor will only stand as high as atmospheric pressure will permit. The best illustration of this phenomenon is the manner in which atmospheric pressure is measured. A cylinder containing mercury is inverted in a container with a free surface exposed to atmospheric pressure. The mercury will fall, creating a vacuum at the top, until the pressure at the level of the free surface of the mercury is the same as atmospheric pressure (Figure 7-9). Mercury has a specific gravity of 13.6 or a mud weight of 13.6 (8.34 ppg) = 113.4 ppg.

As the pipe is lowered, the surge pressure at the surface cannot be measured until the pipe is filled. For this reason, a valve must be placed in the drillstring below the liquid level when the pump is stopped (Figure 7-10). A short sub with a hydraulic hose can be connected to a pressure transducer or pressure gauge to measure the surge pressures.

7.6 Practical example of determining gas units

Crawdad Drilling Company was drilling with a dull bit at 16,789 ft with a 16 ppg water-based drilling fluid. The gas units from the last connection went up to 900 units, but dropped back to the 200 unit background level in only eight minutes after the peak was reached. Just after the connection, the drilling rate increased from 15 ft/hr to 40 ft/hr. During the pump shutdown to flow check the drilling break, the gas reached 950 units, but fell back to the background in only 5 minutes. The company representative decided that a 10 stand short trip might be prudent even though the flow check indicated that the well was not flowing. The short trip was successfully completed without incident and the gas bubble pumped to the surface. The maximum gas during the pump-out was 700 units. The gas units required 15 minutes to fall back to the background level.

The company representative had once coped with an unexpected influx into the wellbore while the drillpipe was out of the hole. Once was enough experience and he did not feel that he needed more practice stripping into a well again. He had the rig pull a 40 stand short trip and was pleased with the results. The gas during the pump-out only reached 650 units but required 25 minutes to return back to the background.

Decision time: Is the mud weight sufficient? Can the company representative plan to change the bit safely? Answer in Appendix 7A.

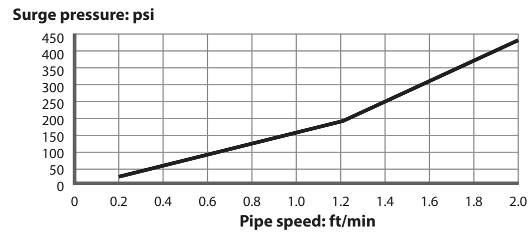


Figure 7-8: Calibration chart to convert surge pressures to swab pressures.

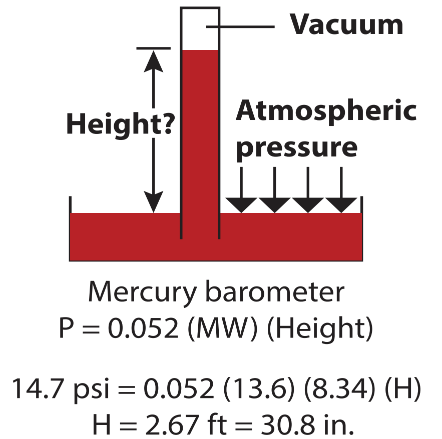


Figure 7-9: Measuring atmospheric pressure. If a 12.0-ppg drilling fluid is used instead of mercury, normal atmospheric pressure will allow the fluid to stand about 23.6 ft above the free liquid surface. On a drilling rig, when the pumps are turned off, a 12.0 ppg drilling fluid will only stand 23.6 ft above the fluid level in the annulus (or above the flow line to the shale shakers).

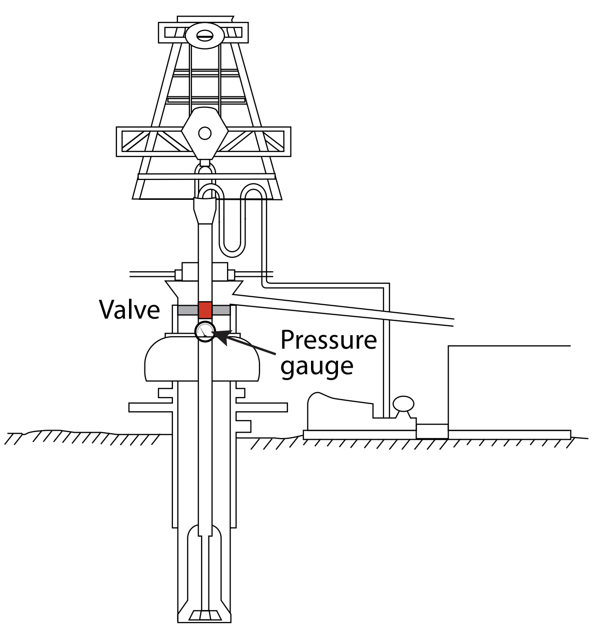


Figure 7-10: Location of valve needed to measure surge pressures in the drillpipe.

7.7 Pressure indicators

The casing seat hunt team must use a variety of indicators to assist in detecting abnormal pressure. Almost all of the traditional methods are secondary indicators. This means that pore pressure is not measured directly. Many parameters respond to abnormal pressure but require interpretation.

7.7.1 Factors affecting mud logger gas units

Mud loggers measure combustible gas extracted from the drilling fluid in the shale shaker possum belly (or back tank). This gas is pulled into the mud loggers through a plastic hose and passes through several measuring units. The principle measurement is the gas unit. The area under the mud logger's gas unit/time curve represents the volume of gas arriving at the surface. During sequential connections, if the area under the gas-unit/time curve increases continuously, the pore pressure in the formations is probably increasing. The swab pressure is assumed to be the same during each connection. So the additional gas is entering the well-bore comes from the decrease in differential pressure.

Maximum gas units are frequently erroneously used to indicate the onset of abnormal pressure. The same volume of gas entering a wellbore can give different results at the surface. A maximum gas unit value could be very high if the drilling fluid is very thick and very low if the drilling fluid is very thin, depending upon how a gas bubble is stretched as it arrives at the surface. The area under the gas unit curve (gas units vs. time) would be the same in both cases. The high gas unit value would last only a short time and the low gas unit value would last a longer time.

Trip gas is also a good indicator of overbalance. One technique to evaluate the pressure balance at the bottom of a borehole is to make a "short trip". For example, 10 stands are pulled from the borehole and racked back, then immediately put back in the borehole. Drilling fluid is circulated until the fluid from the bottom of the hole arrives at the surface. Gas content and/or chloride content gives an indication of whether much formation fluid entered the wellbore as the drill bit was moved up the hole during the trip.

7.7.2 Drilling rate

Drilling rate is dependent upon the pressure across the bottom of the borehole. If the pressure differential increases, the drilling rate of a roller-cone bit decreases; if the pressure differential decreases, drilling rate of a roller-cone bit increases. Drilling rate also depends upon the ability to clean the cuttings from the bottom of the hole, the rotary speed, weight on bit, type of drill bit and diameter of drill bit. To use drilling rate as a pressure indicator, attempts should be made to keep everything constant that can be controlled. This means that the rotary speed and weight on the bit should be held constant. Because the cutting mechanism of the PDC bit is different, PDC bits do not always show an increase in drilling rate when the bottom hole pressure approaches the formation pore pressure. Particularly in shales, a PDC bit can drill significantly faster when a larger pressure differential is applied. (See discussion in Chapter 5.)

If the bit is tripped during the casing seat hunt, the bottomhole assembly, bit type and bit diameter should remain constant. As the pore pressure increases, the pressure differential across the bottom of the hole will decrease. This will be reflected in an increase in drilling rate. If a milled tooth drill bit is used during a long casing seat, a dulling trend may be superimposed on the drilling rate changes. The dulling trend tends to decrease the drilling rate while the pore pressure increases tends to increase the drilling rate.

Both the drilling rate and "d" exponent should be plotted as the bit drills. Selecting the proper scale for plotting is frequently difficult and is very "site-specific". Initially, two or three simultaneous plots with different scales may be necessary to help reveal trends.

Another difficulty with interpretation as the well is being drilled, is accounting for formation changes. Shales normally drill more slowly than sands with roller-cone drill bits. If the sand content of a shale formation increases, the drilling rate would increase. (This might be falsely interpreted as an increase in formation pore pressure). Correlation logs are very helpful for proper analysis.

7.7.3 Drilling fluid properties

An increase in chloride content in a water-based drilling fluid usually indicates that formation fluid is entering the wellbore. Formation fluid is usually saltier than fresh water drilling fluid. Small influxes reveal very slight increases in chlorides. Large influxes, of course, will be detected by an increase in pit volumes. Just prior to an intense kick, careful analysis of the chlorides content may be an indicator or prelude before a very permeable formation is drilled.

Flowline temperature can sometimes provide an indicator of abnormal pressure. In some South China Sea drilling the temperature gradient abruptly increases just above abnormal pressure. In East Texas, the same abrupt temperature gradient increase is a false indicator of abnormal pressure.

7.7.4 Paleontology

Frequently, some formations are known to contain high pore pressures. If the strata above these formations can be identified, casing seats can also be safely set close to the abnormal pressure formation. Paleontologists can assist greatly in verifying and identifying formations during a casing seat hunt.

7.7.5 Cuttings

Formations above abnormal pressure may also have a distinctive color or composition that can be a prelude to abnormal pressure. As pore pressure increases in shales, shale slivers can pop off the wellbore. This is caused by the pore pressure in the shales causing a tensile stress and either a shear failure or a tensile failure. These slivers are distinctive and much larger than cuttings from a drill bit. They can also be caused by the absorption of water from the drilling fluid into the clay matrix. Water absorption will increase the pore pressure in shales and also create the same failure mode. Sequential sonic logs taken two or three days apart may indicate the formation fluid pressure in the shale is increasing. This change in sonic velocity is created by water absorption into the clay structure, not by naturally occurring increases in formation fluid pressure.

In abnormally pressured reservoirs, the shales have not been compacted as much as normally expected because the liquid in the pore spaces is still supporting some of the overburden. Normally shales become more dense with depth. A natural trend line can be developed from the shale density and depth. When the shale density ceases to increase along this trend line, the pore pressure in the shale is higher than it should be for that depth. This is an indicator of abnormal pressure.

7.7.6 Hole conditions

This is one of the most difficult of all indicators to use, because so many things affect hole conditions. If the pore pressure is increasing with depth and the mud weight is kept constant, the differential pressure between the fluid pressure in the formation and the wellbore is decreasing. This can lead to faster drilling with rollercore bits, as discussed, as well as an increase in cuttings falling into the borehole. Generally, if excessive shale sloughings fall into the wellbore, torque and drag on the drillstring increase. This increase, however, could also be caused by many other factors. Some shales will absorb water, resulting in an increase in pore pressure. These cuttings or sloughings resemble those that pop into the wellbore from naturally occurring pore pressure. Even under normal drilling conditions, if the carrying capacity of the drilling fluid is not sufficient to bring cuttings to the surface, torque and drag on the drillstring will increase.

7.8 Lost lag

Many times while drilling very permeable formations, the mud logger "loses the lag gas". Calcium carbide converts into acetylene when it contacts water — creating the flammable gas the mud logger detects to determine the lag time for circulation. In many wells, the gas converts to a small quantity of liquid which filters into the formation. The methane used in the calibration process makes a good alternative.

Popcorn can also be used. The downside of this method is that the mud logger must be standing beside the shale shaker to record the time required for the popcorn to traverse the well. It may also arrive at the surface a little faster than the acetylene could. Gas may take a slower path because the spinning drillstring tends to throw solid particles out into a faster flow stream and the lighter material moves toward the twirling drillstring.

The use of popcorn was selected instead of the old method of using rice. For surface holes In very cheap operations, drillers would use rice as a method of determining hole size. With a known annular velocity and the time required for the rice to transit the well, the cross-sectional are a could be approximated. This was needed to order cement volumes for setting the surface casing. Rice was used in the hole above but bottom hole temperature was too high and only gumbo came back. The popcorn doesn't pop. It makes a disc about ⅜ in. diameter and about ⅛ in. thick and is relatively easy to see on the shaker screen.

7.9 Correlation

Well logs of offset wells can supply much information about formations to be drilled. Formations, however, even in relatively flat terrain, can have unexpected changes in horizon tops and thicknesses. Subsurface features are sometimes as irregular as those observed on the surface. Even at the beach, for example, where the land is relatively flat, sand dunes can build, channels can be cut in the beach and irregularities are prevalent. This should serve as a warning about correlations. Formation tops sometimes correlate well with offset logs and make a good reference point.

Mud loggers will have offset electric logs as well as mud logs. Anticipating abnormal pressures can lead to following strong suggestions of facts that don't really exist. Correlations with offset information should be secondary consideration to information from the current wellbore.

Good advice "Listen to the well!!"

7.10 Penetration rates

When the pressure differential between the pressure at the bottom of the borehole and the pressure in the formation decreases, drilling rate increases. The weight on the bit and the rotary speed of the bit are maintained at a constant value. Drilling rate will then change because of formation drillability or because of pressure differential. The drilling rate equation for a roller-cone drill bit, which seems to fit most experiments reported in the literature (up to the founder point), is:

$$ROP = \frac{kW^2 N^{0.7}}{m + \Delta P}$$

Equation 7-1

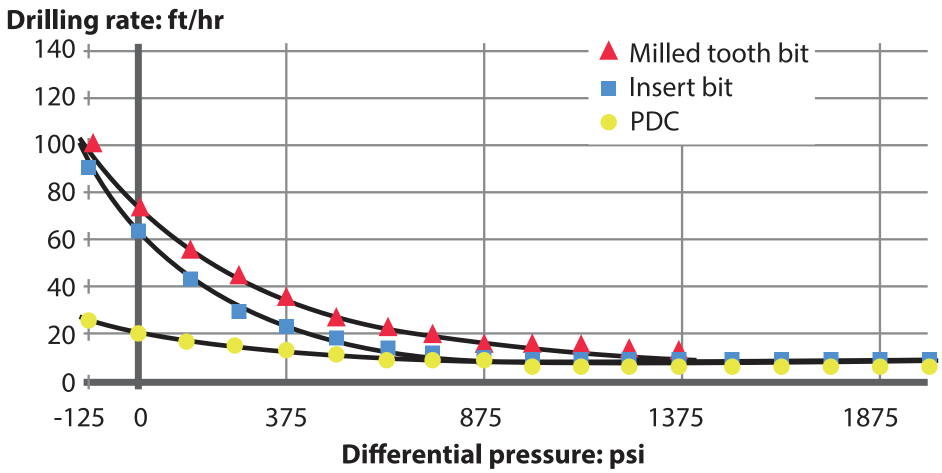


Figure 7-11: The PDC bit is not affected by differential pressure as much as roller-cone bits.

Where:

- ROP is the rate of penetration
- K is the rock drillability
- W is the weight on bit
- N is the rotary speed
- m is a constant
- ΔP is the pressure differential across the bottom of the borehole

Only laboratory data can be used to be certain that the bottomhole pressure and formation pressure are known and controlled. All of the data in the two graphs above were taken with full-scale drill bits drilling in a laboratory-controlled environment.

All of the lines above can be matched with the equation:

$$ROP = \frac{B}{m + \Delta P} \qquad \textbf{Equation 7-2}$$

where B is a constant representing the product of the drillability, and a function of weight on bit and rotary speed.

7.10.1 "d" exponent

The traditional method of using drilling data to determine the onset of abnormal pressure is with the calculation and resulting trends of the "d" exponent. The "d" exponent concept comes from representing the drilling rate equation by:

$$ROP = K\left(\frac{W}{D}\right)^{d} N \qquad \textbf{Equation 7-3}$$

Where:

- ROP is the rate penetration
- K is the rock drillability
- D is the drill bit diameter
- W is the weight on bit
- N is the rotary speed

If the rock remains constant, K will be constant. If the bit diameter, the weight on bit and the rotary speed are also maintained constant, the only variable on the right side of the equation is "d". As the pressure differential decreases, the drilling rate increases. Since everything on the right side of the equation is constant, "d" is the only variable left to change as the differential pressure changes. This is the result of not including all of the variables in the equation. Although it is clearly an artificial variable, the technique can be used to assist in locating increases in the pore pressure if the mud weight is maintained constant. Remember, however, that the actual value of "d" is really a constant value of 2 in the equation that includes all of the variables.

To solve for the "d" exponent, take the logarithm of both sides:

$$\mathrm{Log}\,\frac{ROP}{N} = d\,\mathrm{Log}\left(\frac{W}{D}\right) + \mathrm{Log}\,K \qquad \textbf{Equation 7-4}$$

The logarithm of K is discarded and this equation solved for "d" with the appropriate constants to change units. For example, ROP is in feet per hour (fth/hr) and this is divided by revolutions per minute (RPM). To change the minutes to hours, the denominator is multiplied by 60 min/hr. The constant "12" changes the bit diameter from inches to feet.

The traditional "d" exponent equation becomes:

$$d = \frac{\mathrm{Log}\,\frac{ROP}{60N}}{\mathrm{Log}\,\frac{12W}{10^{6}D}} \qquad \textbf{Equation 7-5}$$

Since mud weight is sometimes increased during a casing seat hunt, the pressure differential between the bottomhole pressure and the formation pressure will cease to decrease. When this happens, the drilling rate no longer increases. To account for this phenomena with the "d" exponent, suggestions have been made to modify the exponent by multiplying by the ratio of the new mud weight and the original mud weight. This has been called the "corrected d exponent" or d_c.

As discussed in Chapter 4, the drilling rate with PDC bits does not correlate with the equations above. The pressure differential changes the mode of failure on the rocks. Even though a rock might become stronger with the application of pressure differential, the drilling rate with a PDC bit can increase instead of decreasing.

7.11 Other tips

Mud loggers normally insert calcium carbide into the drillpipe during a connection. The calcium carbide can be wrapped in paper which dissolves as the drilling fluid carries it down the drillpipe. The calcium carbide reacts with water and generates acetylene. Acetylene can easily be detected by a mud logger to identify the number of pump strokes required to circulate drilling fluid all the way around the well. When casing seat hunting, usually a large amount of open hole is exposed above the drill bit. As the hole sloughs into the well and the hole diameter increases, annular velocity can decrease appreciably. This will lengthen the lag time. The lag needs to be calibrated occasionally.

Casing seat hunting in deep wells is particularly difficult because of long lag time. Patience is required to circulate bottoms up when doubt arises about situations. One of these situations could be a drill break where the drilling rate increases by a significant factor. This could mean that the drill bit has penetrated a permeable formation with a pore pressure that is above the pressure within the borehole. The admonishment is "don't overdrive your headlights". When driving an automobile in the country, the automobile speed could be so high that the car will travel past the point where the headlights reach before the driver can react. This is a recipe for disaster in the car or in a well.

During a casing seat hunt all members of the team must effectively communicate with each other and provide the necessary interactions to insure a success. Communication is crucial. In different parts of the world different indicators are effective. Use the ones that work in your part of the world. With the high mobility of drillers in the world now, all of the indicators should be part of everyone's repertoire.

7.12 Driller's response to drill gas

Frequently, background gas will increase and be very high while drilling some shale intervals. The natural tendency of many drillers is to suppress the back ground gas by increasing the mud weight. Background gas is not necessarily caused by an influx of hydrocarbons into the wellbore. Some shales contain a large porosity and are filled with hydrocarbon gas. As the shale is broken, the gas is liberated. A teacup of gas under bottomhole pressures and temperatures can expand to gallons of gas at the surface. The indicator should be the volume of gas which enters the wellbore during connections and/or enters the wellbore after a short trip.

Shales with a high gas content will drill rapidly with roller-cone bits. This high ROP frightens some drillers because it is frequently associated with increasing pore pressures. One well in South Texas was drilling at 70 ft/hr with a roller-cone bit at 17,000 ft with a 17-ppg drilling fluid. Connection gas was minimal. Increasing the mud weight at this time could have easily cut the ROP in half. Several permeable sands were penetrated without a kick.

Appendix 7A: Solution to problem described in Section 7.6

Crawdad Drilling Company was drilling with a dull bit at 16,789 ft with a 16-ppg water-based drilling fluid. The gas units from the last connection went up to 900 units, but dropped back to the 200 unit background level in only 8 minutes after the peak was reached. Just after the connection, the drilling rate increased from 15 ft/hr to 40 ft/hr. During the pump shutdown to flow check the drilling break, the gas reached 950 units, but fell back to the background in only 5 minutes. The company representative decided that a 10 stand short trip might be prudent even though the flow check indicated that the well was not flowing. The short trip was successfully completed without incident and the gas bubble pumped to the surface. The maximum gas during the pump-out was 700 units. The gas units required 15 minutes to fall back to the background level.

A simple sketch of the description of the behavior of the gas unit curve will reveal that the short trip produced a significantly larger quantity of gas than connections did even though the maximum value is lower. The increase in drilling rate with a dull bit is another indication that the differential pressure at the bottom of the hole is insufficient to prevent gas influx. Increase the mud weight before tripping out of the hole.

Chapter 8
Cementing

TABLE OF CONTENTS

8.1 INTRODUCTION

This chapter provides some guidelines for processes needed to correctly cement casing in place. Many other books and manuals are available to describe slurries, testing, formulations and other factors for cement performance. The suggestions in this chapter concentrate primarily on procedures that have been proven to work and are frequently ignored because they are inconvenient for easy cementing.

Summary of guidelines discussed in this chapter:

- While drilling, keep the drilled solids very low to create a very thin, slick filter cake. This allows the casing to go to bottom and be easily moved while the cement is flowing up the annulus;
- Try to drill a gauge hole: account for BHA vibration, mechanical and chemical effects which enlarge the wellbore;
- Treat the drilling fluid to make it easy for the cement to displace;
- Centralize the casing;
- With NADF, the spacer fluid should make the casing and shale formation water-wet;
- Move the casing (preferably "rotate") while cement is displacing the drilling fluid in the annulus;
- Account for the decrease in hydrostatic pressure while the cement is setting;
- Keep the excess water to a minimum value;
- Keep the cement filtration rate below 50cc/30 min.

8.2 Keep drilled solids out of the drilling fluid

Most companies demand that casing must be run into the hole all the way to bottom. If the drag and torque increases significantly as the casing is going in the hole, drillers are very reluctant to reciprocate the casing after it reaches bottom. Their performance evaluation is frequently based on whether the casing was cemented on bottom. Their performance is not usually predicated on whether the cement job failed to seal the annulus.

This problem must be addressed at the top of the hole interval and not after the hole has been drilled. Oil-based, or non-aqueous fluids (NAF), reportedly are very tolerant of drilled solids. They are when the criterion is based on rheology but not when the criterion is based on the filter cake deposited during the drilling operations. Drilled solids in the drilling fluid may reduce the fluid loss but increase the filter cake thickness. If the colloidal solids increase in the drilling fluid, the surface areas increase rapidly and almost exponentially. Liquid must wet those surfaces, leaving very low free liquid for filtration. Even though the fluid loss may stay the same with increasing pressure, the filter cake will increase significantly — even in a NAF.

Many benefits are usually credited to having very low drilled solids concentration in the drilling fluid (less stuck pipe, less lost circulation, higher flounder points, etc); however, one of the greatest benefits that is frequently not mentioned actually involves getting a good cement job. Stuck pipe may require several days of rig time; but a poor cement job may have a much higher price. Cement must stop flow behind casing, which has a very great effect on the total hydrocarbons produced.

The secret to fast, trouble-free drilling is having a good drilled solids removal system. Keep the drilled solids concentration was close to zero and trouble costs tend to disappear. This is discussed more thoroughly in the chapter on Solids Control.

8.3 A drilling fluid is not a good fluid to be displaced by cement

Drilling fluids are rheologically designed to carry cuttings up the hole to the surface and to suspend particles, such as barite and cuttings. This means that the gel strength and low-shear-rate viscosities are elevated. Difficulty arises when this drilling fluid needs to be displaced from the annulus by cement.

Most often the casing is depicted as being centered in a nice smooth round hole. The annulus is shown to have a uniform thickness around the casing (Figure 8-1).

Unfortunately, most wellbores are not smooth and perfectly round and the casing is frequently not in the center. Most "vertical" wellbores are not perfectly vertical. Angles of 3°, 4° and 5° off vertical are common. Over a long interval, the casing is closer to one side of the wellbore than centered (Figure 8-2).

The location of the casing in Figure 8-2 could also be used to describe its location in a high-angle hole. The forces hold-

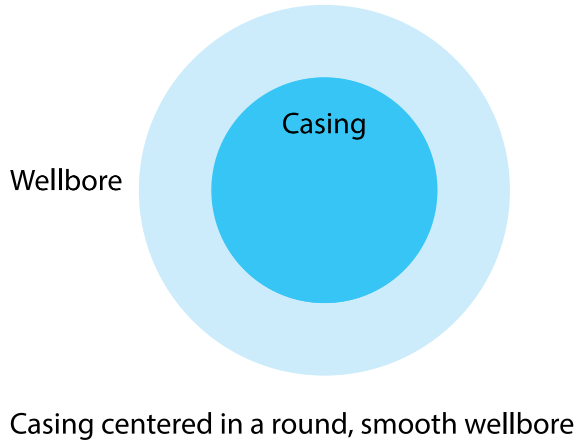


Figure 8-1: Uniform annulus.

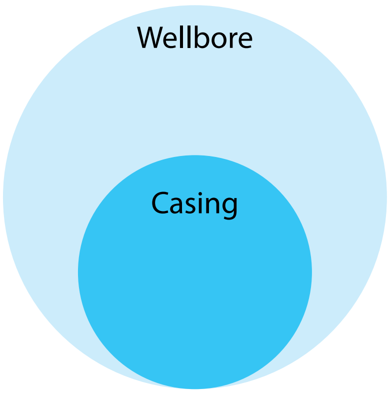


Figure 8-2: Casing adjacent to the low side of hole.

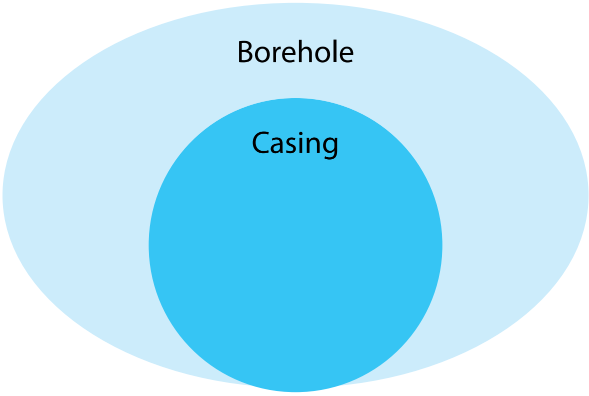


Figure 8-4: Casing in an elliptical, non-vertical hole.

ing the casing next to the formation would depend upon the weight of the casing and the hole angle. Without centralizers and pipe movement, very little cement would move into the narrow region of the annulus. In high-angle holes, non-rotating, solid body stabilizers are needed to provide space for cement under the casing.

Hydrocarbons are usually found in stratagraphic traps. This means that some tectonic stresses have been applied to the formation to cause it to deform. The two tectonic stresses perpendicular to the wellbore will generally not be the same. Frequently, the stress difference will be large enough so that the shear stresses are sufficient to cause the hole to collapse in a non-uniform manner. Wellbores in many hydrocarbon-bearing basins can be elliptical instead of circular. They will collapse in a direction along the maximum stress (Figure 8-3). (Note: The wellbore will fracture perpendicular to the smallest stress — or in the direction of the largest stress.

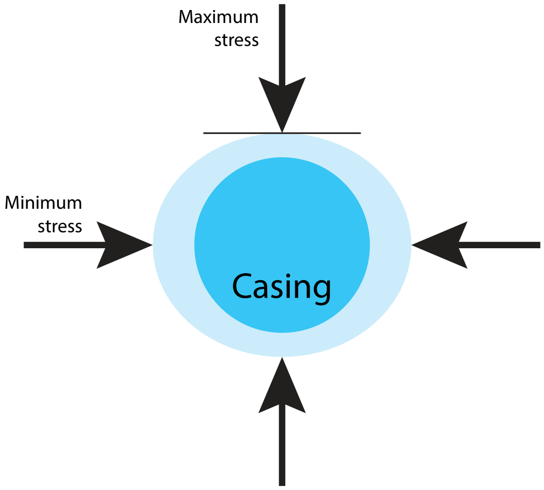


Figure 8-3: Elliptical wellbore with casing centered.

This information is valuable to reservoir engineers who may want to water-flood the formation after fracturing. Production wells can be drilled perpendicular to the fractures in order to improve sweep efficiency and conformance.)

Even with the casing centered in the elliptical wellbore, the areas available to flow vary around the casing. Cement can displace gelled drilling fluid more easily in the large areas (near the smallest stress) than in the small areas (near the largest stress).

Of course, the casing may not be exactly centered in the elliptical wellbore because of the hole angle (Figure 8-4).

In this case, great difficulty will be experienced trying to displace the drilling fluid from the low side of the borehole and obtain a good cement seal.

8.4 Centralize the casing

Even in an elliptical hole, casing can be centralized with solid-blade, spiral centralizers. This will provide the same stand-off distance on both narrow sides (Figure 8-5). When the easily displaceable fluid is in the annulus, cement can remove it from those narrow regions.

Figure 8-5: Solid blade centralizers — spiral (left) and straight blades.

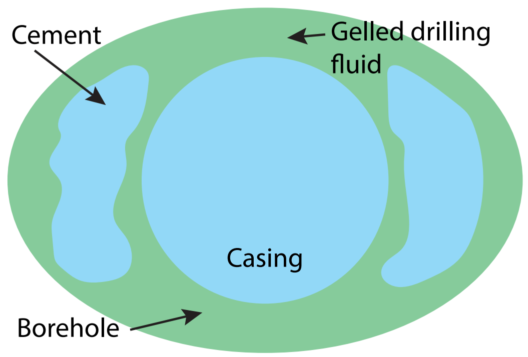


Figure 8-6: Cement will not displace very viscous or gelled drilling fluid.

Another action should to be taken to obtain a good cement job for off-center casing in an elliptical hole. The drilling fluid should be modified so that it can be more easily displaced by cement. This modification of drilling fluid properties should be performed while the drill bit is in the hole, just prior to running casing. In most wells, this would be during the clean-up, or wiper trip, after logging the well. Circulate the hole clean with good carrying capacity. After cuttings cease arriving at the surface, reduce the low-shear-rate viscosity. This fluid should be circulated up the annulus while rotating and reciprocating the drill string to help displace the original drilling fluid. In an unweighted drilling fluid, the yield point and the gels can be reduced greatly from the values needed for the carrying capacity required to bring cuttings to the surface. In a weighted drilling fluid, sufficient gel structure should remain to prevent barite sag. Usually, this means that the drilling fluid yield point (YP) can be substantially reduced. Drilling fluid properties and their significance is discussed in greater detail in Chapter 13 (Drilling Fluid Properties). When the casing is run, the easily displaceable fluid will remain in the narrow regions of the hole.

Changing the drilling fluid properties after the casing is in place will not provide a good cement job. If the drilling fluid is not changed before casing is run in the hole, a gelled drilling fluid will surround the casing when it reaches bottom. A gelled drilling fluid in the narrow annulus illustrated in Figure 8-6 will be difficult to remove.

Flow will be diverted to the larger regions in the annulus and the gelled drilling fluid will remain in place when the cement passes through this interval. Drilling fluid with lower values of low-shear-rate viscosity will not replace the original drilling fluid any better than the cement will. Changing fluid properties before the casing is run will allow the easily displaceable fluid to completely fill the annulus. The narrow regions of the annulus can more easily be displaced by the cement.

8.5 Spacer fluids

Cement will not adhere to an oil-wet surface. When drilling with non-aqueous fluids (NAF), surfactants are included in the fluid to keep everything in the system oil-wet. The casing and rock are made oil-wet. The spacer fluid normally included between the drilling fluid and the cement has an additional task of rendering surfaces water-wet. The wettability of the casing is relatively easy to change. Filter cakes on formations usually are not easily removed with the spacer fluid or the cement. The bonding of the cement to the impermeable (shales) formations becomes crucial to provide flow barriers in the annulus.

8.6 Move the casing

An assist is needed to ensure that the cement does reach those narrow regions shown in Figure 8-6. Casing should be rotated while the cement is flowing up the annulus. This will help move cement into the narrow regions and provide complete coverage of the annular area. If rotation is not possible, reciprocation will be a poor substitute but it will be much better than not moving the casing.

Many tests in various laboratories have a unanimous consensus: failure to move the casing while cement is flowing in the annulus creates a bad cement job (Figure 8-7).

In the examples shown in Figure 8-7, drilling fluid was circulated through a 10-ft long, large-diameter sandstone core under pressure and at an elevated temperature. After a filter cake was deposited, cement displaced the drilling fluid without changing the differential pressure. In these tests, the casing could be positioned in the hole, rotated and/or reciprocated.

Boreholes are not always exactly vertical and perfectly round. Usually a narrow space will exist on one side of the casing and a larger area will be available for cement to flow on the other side. No cement may enter the narrow region of the annulus usually unless the casing is moved.

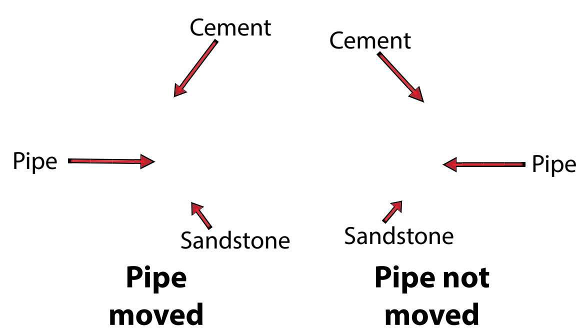


Figure 8-7: Laboratory test showing drilling fluid displacement with cement.

Rotate and reciprocate the casing if possible. This will be the best way to cover all of the annulus area with cement. Rotation is the most important movement of the casing.

A note of warning here:
If drilled solids have not been removed from the drilling fluid and a thick, gritty filter cake is deposited on the wall of the borehole, drillers will be reluctant to lift the casing for fear of sticking the casing off bottom. Good solids control — or more specifically — a very low drilled solids concentration in the drilling fluid is needed to achieve the proper casing movement.

8.7 Account for loss of hydrostatic pressure when cement sets

The behavior of cement when it is fluid and after it sets into an impermeable body is easily understood. It follows common laws associated with liquids and solids. However, as the cement transitions from a liquid to a solid, the phenomenological events which occur are not always intuitive.

When pouring a slab of concrete (or cement), a vibrator is frequently used to "settle" the cement into a homogeneous mass. This allows the air to move to the surface, which creates a more uniform slab. Air is easily entrained in cement, as demonstrated by the invention of the pressurized mud balance in the field. This device was created because the entrained air prevented an accurate measurement of the density of the cement. Entrained air is compressed as cement is pumped down a borehole and contributes little to the change in density at depth. When pouring a slab of concrete in areas where blasting is required to move rocks to build structures, a blasting moratorium of 12-24 hr is frequently observed, While the cement is setting, shock waves from nearby blasting will prevent cement from setting properly.

After pumping cement in a well, the cement starts creating a structure similar to a gel. This structure needs to be understood to properly seal an annulus behind casing. As this gel structure is created the pressure in the cement column changes. This effect and the cement structure needs to be understood to properly seal an annulus behind casing.

8.7.1 Simple model

Water is a simple Newtonian fluid. In a closed container, pressure exerted on water is transmitted throughout the liquid. This can also be calculated by assuming that Poisson's ratio of water is 0.5. If a vertical stress is applied to a body, the horizontal stresses can be calculated by the equation:

$$\sigma_{vert} = \frac{\upsilon}{1 - \upsilon} \sigma_{horiz} \qquad \textbf{Equation 8-1}$$

Where:

σ_{vert} is the vertical stress
υ is Poisson's Ratio
σ_{horiz} is the horizontal stress

When Poisson's ratio is 0.5, the horizontal stresses are the same value as the vertical stress. In rock formations, the horizontal stresses are usually much smaller than the vertical stress (or overburden). Poisson's ratios vary with rock types and can be as low as 0.2.

Lithology	Poisson's ratio
Sandstone	0.21–0.38
Shale	0.20–0.40
Limestone	0.18–0.25
Cement	0.12– 0.26

When cement is "setting up," or starts becoming unpumpable, the material is transforming from a liquid into a material with a Poisson's ratio less than 0.5. This transformation causes cement to change from a liquid to a material that resembles jelly or pudding as it slowly becomes a solid. After cement sets, Poisson's ratio could be in the range of 0.12 to 0.26.

As a drilling fluid gels, the same effect is observed. A vertical stress (or a pressure) applied to the top of a column of these materials will not be transmitted throughout the material undiminished.

The decrease in hydrostatic pressure could cause an influx of formation fluid into a wellbore if the pressure in the wellbore decreases below the formation fluid pressure. An erroneous solution to solve this problem is to incorrectly consider applying a pressure to the top of an annulus to replace the pressure loss as cement starts to set.

Data from field measurements indicate that pressure within the cement column starts to decay almost immediately after the cement pumps stop. In some wells, very low pressures have been measured which were significantly below a simple water gradient.

In one well, the pressure decayed to about the hydrostatic gradient of water. In another well, at 1,960 ft, the pressure decreased to a hydrostatic gradient equivalent to 2.3 ppg.

8.7.2 Setting Cement

An excellent paper was published in 1977 in *Scientific American* that discussed how cement sets or becomes "hard". Cement sets by hydration, NOT by "drying". The process described in this paper makes it easy to visualize why hydrostatic pressure is lost as cement sets. When water is added to cement, a gel coating is formed around each grain of cement (Figure 8-8).

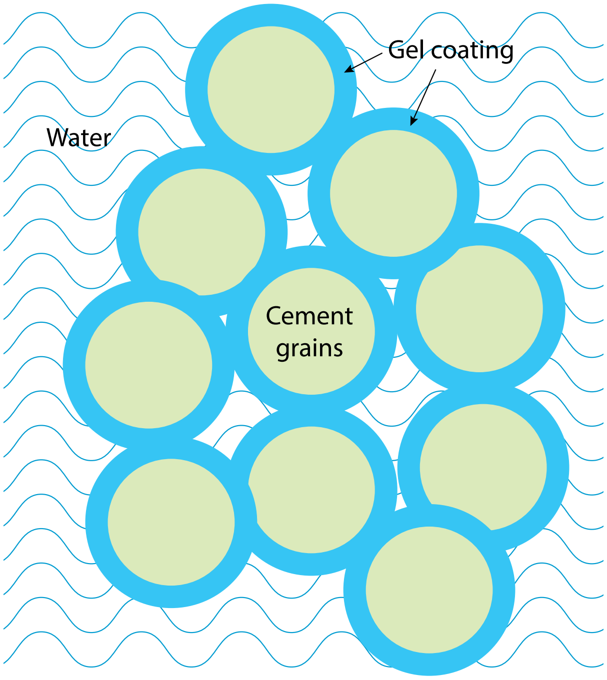


Figure 8-8: A gel coating forms around each grain of cement when water is added.

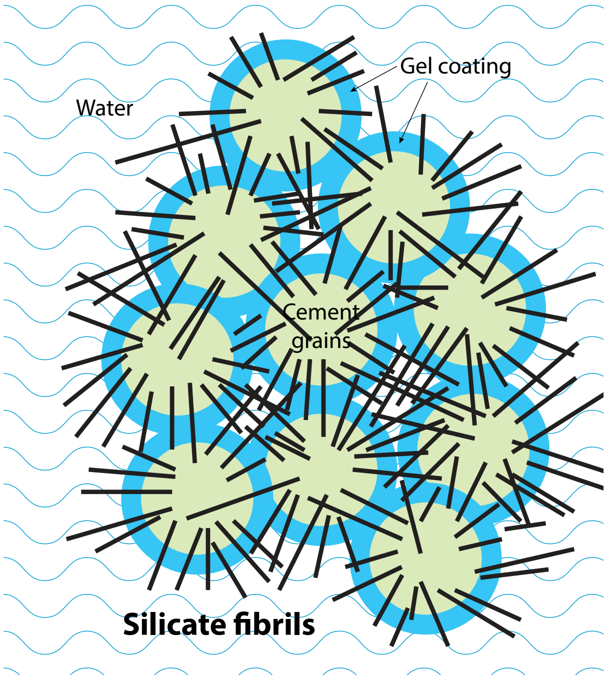


Figure 8-9: Silicate fibrils penetrate the gel coating and interlock with one another to solidify the cement particles into an impermeable mass.

After water interacts with a cement particle, a gel coating forms around the particle. This creates an osmotic pressure within the particle. As more water penetrates the gel coating, fibrils of silicate are forced from the particle (Figure 8-9). These fibrils have been studied with electron microscope pictures of the cement as it sets. Some excellent pictures are published in the Double/Helawell article showing the development of these fibrils.

As water is absorbed into the cement particles and more fibrils extrude through the gel coating, the cement becomes unpumpable. A gel structure is formed and the cement also starts supporting itself.

Cement is pumped down casing and fills some interval of the annulus between the casing and formation. Bottomhole pressure (BHP) is then a combination of the pressure caused by the column of cement and the column of any drilling fluid above the cement. Normally, cement is more dense than the drilling fluid and easily contains formation fluid to prevent a kick. However, as the cement becomes "self-supporting," it is still permeable and the pressure below the column decreases. This is easily visualized in Figure 8-9, where the fibrils and particles start supporting themselves, leaving a column of water to provide hydraulic pressure.

8.7.3 Sand and water column model

This loss of pressure can be demonstrated in a laboratory. A column of sand in water (Figure 8-10), could weigh 9.5 ppg if it is kept agitated. An 8-ft column of this slurry would have a pressure of 3.9 psi. Water would stand 9.1 ft high in a manometer connected to the bottom of the cylinder. When agitation stops, sand settles to be bottom of the container. The sand is now supported by the bottom of the cylinder and not the water. The pressure would decrease to 3.5 psi. Water would now stand only 8 ft in the manometer.

Figure 8-10 primarily reveals the effect of the bottom of the container supporting the sand and not the water. The same effect observed in cement when the cement starts setting but the analysis is more complicated. Water transmits pressure very easily . If the water contains other ingredients, the pressure might not transmit as readily. For example, if the water starts to gel – like jelly, the fluid might not transmit pressure undiminished throughout the entire column. A rigid jelly tends to act more like a pliable solid instead of a fluid.

The loss of pressure from the same effect can be demonstrated if an 8-ft column of 16.0-ppg cement is placed in a cylinder (Figure 8-11). In this case, the pressure at the bottom of the cement column initially is 6.7 psi. Water would stand 15.35 ft in the manometer. As the cement starts to hydrate and set, the cement particles start supporting themselves instead of the water. The hydraulic pressure at the bottom of the cylinder will drop some amount depending on the gel strength, shrinkage and water migration upward due to gravity and the amount of excess water in the cement. The final pressure can be higher or lower than a water gradient,

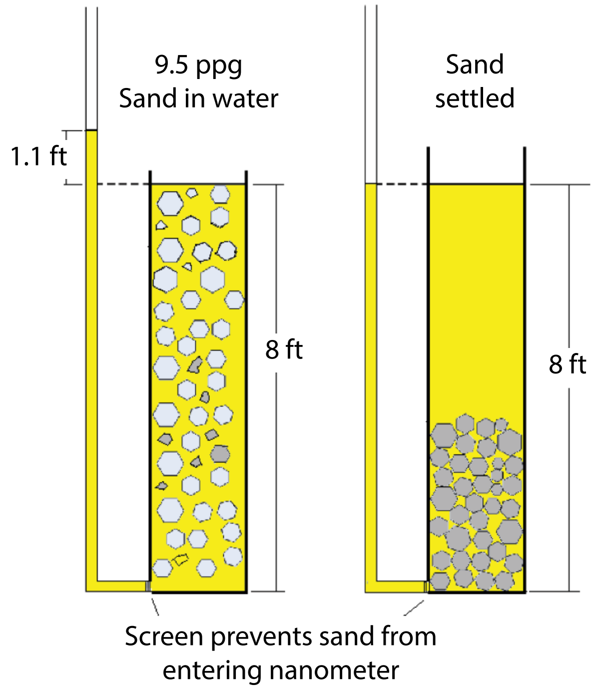


Figure 8-10: Sand in an 8-ft slurry of water. Note the screens that prevent sand from entering the nanometer.

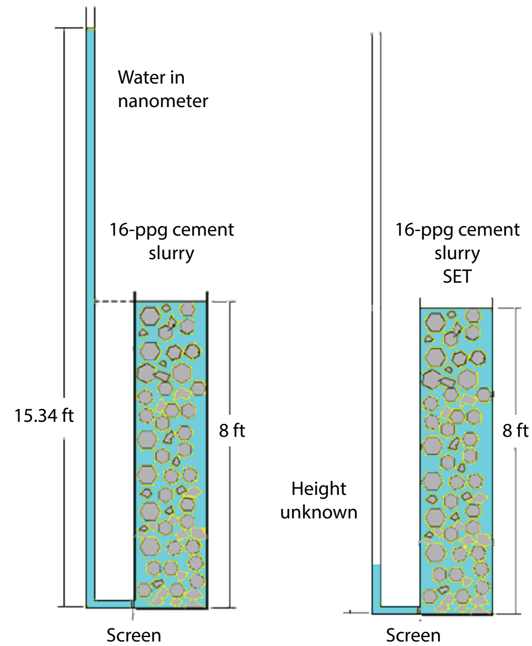


Figure 8-11: Pressure loss as cement sets.

as determined by these three factors. If most of the water is absorbed by the cement particles, the gel structure tends to prevent transmission of pressure.

The cylinder obviously does not exactly duplicate the conditions in an annulus in a wellbore. The wellbore will have permeable zones instead of an impermeable wall. These permeable zones will contain fluid at different pressures. Initially, to prevent kicks and blowouts, the pressure in the wellbore will be higher than the pressure in these formations. In this case, filtration of the free water can have several effects. If too much water is lost, the cement hydration may also be compromised. As the water is lost, the pressure in the cement adjacent to the permeable formation might decrease because of the inability of the gelled cement to continue to apply pressure to the free water. The pressure in the liquid phase of the cement can decrease below the pore pressure of the fluid in the formation. If the fluid in the formation contains gas, the gas can flow easily into the wellbore and start rising in the cement sheath as it sets. This will create "wormholes" or continuous paths for formation fluids to flow within the cement sheath in the annulus.

8.7.4 Laboratory experiments to study cement column behavior

In 1976, Garcia and Clarke reported laboratory experiments begun in 1968 that identified some of the variables that need to be controlled to mitigate the pressure loss from the transition of cement from a liquid slurry to a solid. The five guidelines from this study indicated that:

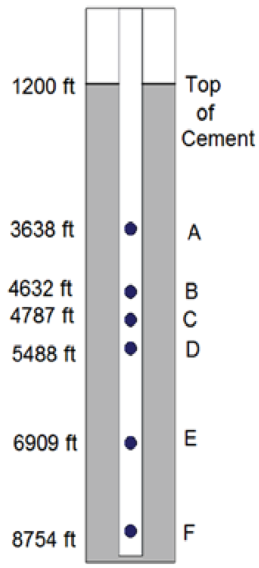
- Cement fluid loss should be as low as possible;
- Mix-water ratio should be as low as possible;
- Where possible, cement should set from the bottom to the top;
- Condition drilling fluid before cementing and move the pipe while cement is flowing up the annulus until the plug bumps;
- Check for annular flow with a noise log — even days after the cement job.

These guidelines have withstood the passage of time and have been validated by many observations in the field.

8.7.5 Field experiments corroborate model findings

The pressure loss phenomenon has also been measured in the field. Pressure transducers and thermometers were strapped to the outside of casing in five different wells (Figure 8-12). A cable was attached to the side of the casing to transmit signals before, during, and after cement was pumped into the annulus. A pressure reduction was observed in all wells as the cement set.

At 1,100 min, most sensors indicated a pressure that was equivalent to the original pressure from the 10.2-ppg drilling fluid. It required around 200 min for the pressure to decline to the drilling fluid pressure. During this period, the cement must set sufficiently so that the formation will not flow into the wellbore.



The results of the measurements on one well are discussed in detail below. The 7 ⅞-in. diameter well, 8,900 ft deep, was drilled with a 10.2-ppg drilling fluid. The top of the 16.0-ppg cement in the annulus was at 1,200 ft.

The well was circulated for almost 780 min before cement reached the first sensor (F) (Figure 8-13). The pressure increased from 4,500 psi to about 7,000 psi as the 16-ppg cement passes by sensor F. Cement did not reach the upper sensor until about 820 min. When the cement was in place and the pumping ceased, the pressure at all positions started decreasing.

Figure 8-12: Location of sensors on outside of casing.

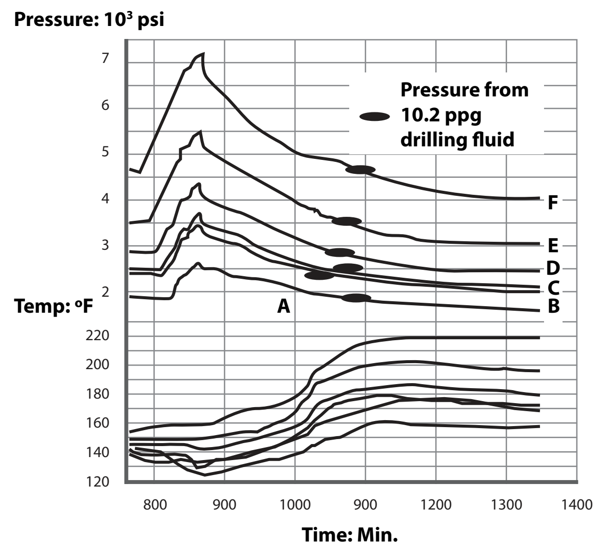


Figure 8-13: Pressure record from one well while cementing.

As the fluid pressure in the cement decreases below formation pressure,fluid may enter the cement and keep the cement ”pore pressure” equal to the formation fluid pressure. If gas is present in the formation and enters the cement column as it sets, a channel will be created as the gas rises through the setting cement. This channel is difficult to “see” with a cement bond log.

In one test well, a pressure of 200 psi was applied to the top of the annulus, about 20 min after pumping ceased. None of the sensors recorded any increase in pressure. This '”back pressure” was not transmitted through the setting cement. The only way to transmit pressure to bottom would be to increase the surface pressure until the gel strength in the mud and cement are broken or by having a means of circulating through a pipe from the surface to the top of the cement. Pressuring up to a high value is likely not possible without breaking the well down when pressuring up on top of an annulus. Circulating to the top of the cement after placement via drillpipe is only possible when setting a liner where circulating can be done through the setting string following completion of the cement job.

When the pressure at the bottom of the cement column decreases and reaches the pore pressure of the formation, fluid can flow from the formation into the cement. If the fluid is gas, the gas rises rapidly in the cement column and causes channels to be formed. Because of their appearance, these are called “wormholes.”

Cement bond logs examine the boundary reflection between the cement and the casing or formation. Acoustic impulses impinge upon the casing, transmitting a vibration to the pipe. This works similar to one method of finding studs behind wall boards. Tapping on an unsupported area gives a different sound (or vibration) than tapping on an area which is supported. The failure of cement to adhere to the casing will be indicated on the cement bond log and creates what is called a “micro-annulus.”Cement bond logs will not show the presence of wormholes. Sometimes their presence can be detected by a noise log. Fluid flowing in behind the casing creates a noise which can be detected with the receivers in the noise log equipment.

Figure 8-14, which is an enhanced pressure vs time plot for the same well as in Figure 8-13, shows that the cement column pressure declined steadily and went below the hydrostatic pressure of the mud weight used to drill the well

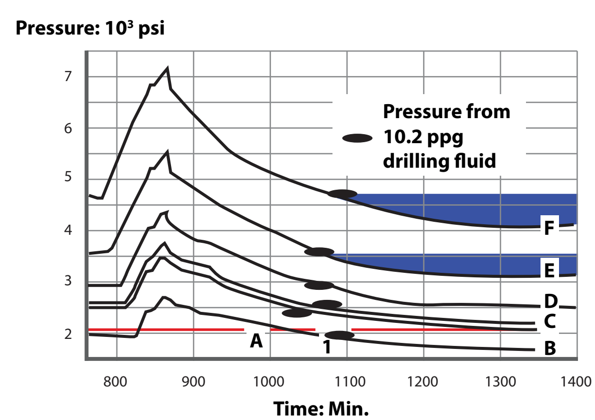


Figure 8-14: Pressures decreased steadily as the cement set.

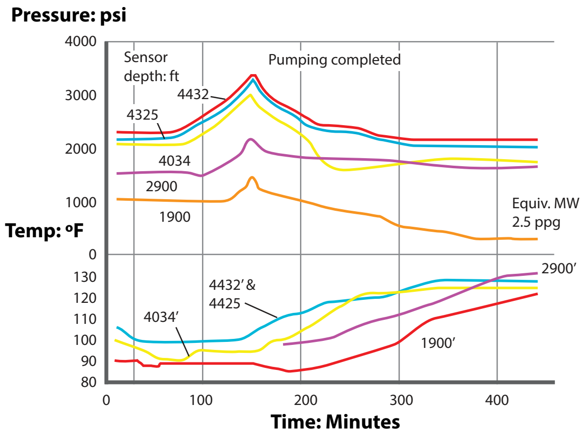


Figure 8-15: Pressure decrease below hydrostatic gradient.

(shown as the blue above the curves for sensors F and E). For example, the pressure at the lowest sensor package (F) decreased another 600 psi below the pressure exerted by the 10.2-ppg drilling fluid before cementing. If the formation adjacent to the lower part of the hole contained fluid, the fluid would enter the cement and tend to flow upward. The pore pressure in the cement would be the same as the formation pressure.

In another well, (Well G) a pressure transducer in the annulus at 1,960 ft indicated the pressure in the cement column decreased to the equivalent of 2.3 ppg (Figure 8-15). If the decrease in pressure was caused by the cement particles supporting themselves or because of filtration into a normally pressured reservoir, the pressure should have decreased to the pressure of the formation opposite the sensor. If, however, the formation in proximity to the sensor at 1,960 ft were impermeable the pressure could drop to a very low value as a result of shrinkage and water migration out of the cement column due to gravity. Without an outside pressure infusion source to the cement as it became a solid, pressure can drop to a very low value when the original in situ pressure is relieved when fluid volume is consumed or dissipated because of fluid migration. This phenomenon was investigated as early as 1976 as presented by Garcia and Clark in SPE paper 5701 entitled, “An Investigation of Annular Gas Flow Following Cementing Operation”.

8.8 Temperature

Temperature changes in the cement after placement can also impact the pressure of the column. The reaction between cement and water is exothermic (Figure 8-13). The major part of the temperature increase occurs as the cement starts to support itself and becomes hard. About 250 min after the cement was in place in the well described in Figure 8-13, the temperature reached a maximum value at all sensors. The impact on pressure at a given depth due to temperature changes will just one more of the factors that influence column pressure behavior along with fluid movement, gel strength and formation pressures opposite the column.

The highest temperature was measured at the deepest sensor. This effect makes it relatively easy to determine the top of the cement column by logging the temperature inside the casing.

8.9 Method to isolate potential flow zones during well construction

In 1980 Sabins, et al, published an equation that described the maximum pressure differential which could be exerted by a column of cement when it reached a critical gel strength:

$$MPR = \frac{SGS}{300\left(\frac{L}{D}\right)} \qquad \textbf{Equation 8-2}$$

Where:

- MPR = maximum pressure restriction, psi
- SGS = Static gel strength, lb/100 sq ft
- 300 = conversion factor
- L = Length of cement column, ft
- D = effective diameter of cement column, in. (hole diameter minus pipe diameter)

This equation was used to predict gas-flow potential in a cemented annulus by Crook and Heathman .

8.9.1 API Standard 65, Part 2, 2nd edition

In 2010, the API brought together a group of industry cementing experts for the purpose of updating guidelines using the best technology and operational knowledge to “help prevent and control flows just prior to, during and after cementing operations.” Their charge was to develop a standard that the industry could use for determining the best way to isolate potential flow zones in wells during well construction. In December, 2010, API published Standard 65, Part 2, 2nd edition, entitled “Isolating Potential Flow Zones During Well Construction”.

Section 5.7.8 of this standard, Static Gel Strength, describes how field studies, experimental data, and field results have been used to develop an empirical method for estimating when the static gel strength of a cement slurry placed in a well reaches a critical point, referred to as the critical static gel strength (CSGS). CSGS is defined as the gel strength value in a slurry which results in the decay (or loss) of hydrostatic pressure of the cement column to the point that pressure becomes balanced (hydrostatic pressure equals pore pressure) across a potential flow formation. Once the pressure of column no longer has an overbalance on the formation, formation fluid can enter the wellbore.

The CSGS can be determined by using the following empirical equation:

$$CSGS = \frac{(OBP)\,(300)}{L/D_{eff}} \qquad \textbf{Equation 8-3}$$

Where:

CSGS is the critical static gel strength in lbf/100 sq ft
OBP is the overbalanced pressure in psi
300 is a unit conversion factor and an empirical constant
L is the length of the cement column above the flow zone, ft
D_{eff} is the effective diameter, in., and is the difference in diameters between the open hole and the casing

This equation is discussed in Appendix 8A.

CSGS represents the static gel strength of the cement when the pressure adjacent to a potential influx zone has decayed to a value equal to the formation fluid pressure.

Experimental data collected by the API Standard 65 Committee determined that a static gel strength value of 200-500 lbf/100 ft in a cement column will prevent gas from perculating through the cement even if an under-balance condition occurs in a wellbore. To be conservative, the API group selected a CSGS value of 500 lbf/100 sq ft or greater as the recommended minimum required to avoid gas percolation through cement. If the CSGS value is below 500 lbf/100 sq ft, the chance for flow from the formation through the cement column is high. If, for example, the CSGS in a cement column is found to be 200 lbf/100 sq ft, this would mean that pressure deterioration in the wellbore will decrease below the point of balancing the potential flow formation pressure while the gel strength is too low to prevent gas from entering the wellbore and percolating up through the cement column.

The CSGS equation indicates that the critical gel strength value that will cause sufficient pressure decay to occur causing flow is a function of three variables. The overbalanced pressure is obviously one of the more important variables. Offshore, however, the window between pore pressure and fracture gradients usually limit this to a fixed value. The space around the casing, or the slot through which the cement moves, is a crucial variable. Larger slot widths permit easier pressure transmission through the column and better bonding but usually this cannot be changed from the program. This leaves only the height of cement column above the potential flow zone as a variable which might be modified. As the pressure decays within the setting cement, the pressure inside the wellbore opposite the flow zone may become less than the formation fluid pressure. If this happens fluid may then enter the cement column. The amount of pressure loss in the column of cement above a potential flow zone for a given increase in gel strength will be proportional to the height of the column. Obviously, a height sufficient to cover the potential influx and some distance above the zone is required but should be kept as short as possible in order to increase the CSGS value.

8.9.2 Impact of cement column height on CSGS

Several different typical hole size/casing combinations can be examined using Equation 8-3, assuming that a CSGS of 500 lbf/100 sq ft has been achieved. As the initial overbalance pressure (OBP) from the wellbore to the potential flow zone formation is increased, the height of the column of cement above the zone can be increased. In most situations, the OBP and the slot width (or difference between the diameters of the open hole and the casing) are known and are not variables. The equation for the critical static gel strength, Equation 8-3, can be rearranged (Equation 8-4) to solve for the height of cement above the potential influx zone.

$$L = \frac{(300)\,(OBP)\,D_{eff}}{CSGS} \qquad \textbf{Equation 8-4}$$

For the recommended value of a CSGS of 500 lbf/sq ft, the maximum height of the tail slurry above a potential influx zone can be calculated (Equation 8-5).

$$L_{max} = \frac{(300)\,(OBP)\,D_{eff}}{500\ \text{lb/100 sq ft}} \qquad \textbf{Equation 8-5}$$

The maximum height of the tail slurry above the potential flow zone for many of the common hole size/casing size combinations, Figures 8-16 and 8-17 indicate that low overbalance pressure values will only allow relatively short columns of cement above the potential influx zone. For example, in Figure 8-17, the top curve (for a 7 ⅝-in. casing in a 9 ⅞-in. hole) can only have a length of 540 ft above a potential flow zone with a 400-psi overbalanced pressure. If the column of tail slurry above the potential flow zone is higher than 540 ft, the pressure adjacent to the potential flow zone will decrease to a value less than the formation pressure. This will cause an influx from the potential flow zone. The taller cement column will lose too much pressure as the cement thickens.

From a conservative approach, the tail slurry should probably only be about 300 ft above the flow zone. The reason for this is because the gellation in the shorter column will result in a lower loss of pressure than the gellation in a taller column.

The height of the slurry above the potential flow zone can

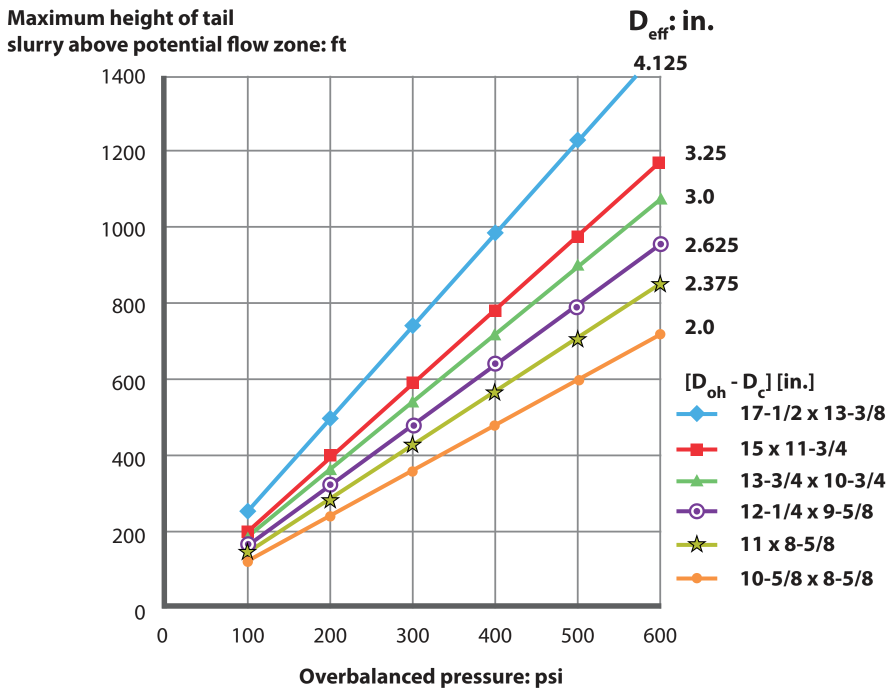


Figure 8-16: Maximum height of cement column above potential flow for different overbalanced pressures.

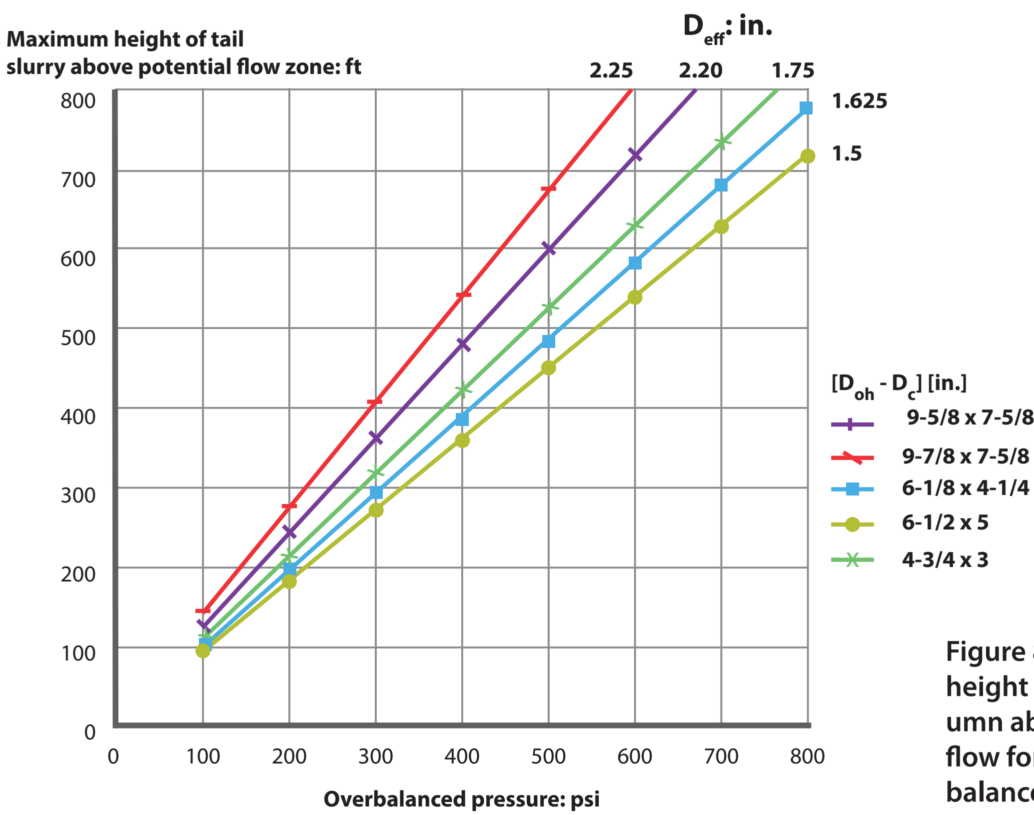


Figure 8-17: Maximum height of cement column above potential flow for different overbalanced pressures.

be relatively low without causing a seal problem when a lead slurry is also used above it, as long as an overbalance pressure can be maintained at the potential flow zone until the tail slurry has set. The lead slurry will ensure that the tail slurry is not mud contaminated because it and a good spacer fluid ahead helps to sweep drilling fluid from the hole to reduce the likelihood of contamination to the tail that follows. Additionally the lead slurry can also provide several more hundred feet of cement above the tail that will set up later and add more height to the final barrier column of cement above the potential flow zone. Regulations may also govern what the minimum height of the total cement column must be.

8.9.3 Critical gel strength period (CGSP)

The experimental data gathered by the API Standard 65 Committee also determined that, in a well cementing case where the CSGS is below 500 lbf/sq ft, the additional time required for the development of a gel strength of 500 lbf/100 sq ft in a cement column across a potential flow zone is critical and very important. The critical gel strength period (CGSP) is defined as the time period starting from the time when the cement has reached its CSGS until it reaches a value of 500 lbf/100 sq ft. If the critical gel strength is above 500 lbf/100 sq ft, this means that the wellbore pressure adjacent to the potential flow zone will remain above the pore pressure until the cement gels sufficiently to prevent an influx and there is no problem.

If the CSGS is lower than 500 lbf/100 sq ft, the CGSP becomes very important in preventing gas breakthrough to the top of the cement column. In this case, it will be a race against time. The time period is determined in the laboratory by measuring the gel strength for the cement slurry under downhole conditions as it thickens over time. If, for whatever reason, the CSGS cannot be accurately determined, a conservative value of 100 lbf/100 sq ft can be used as a starting point. The cement slurry should be designed to transition quickly from its CSGS value to the desired gel strength of 500 lbf/100 sq ft. The race against time starts after CSGS has occurred (if it is below 500 lbf/100 sq ft) and the potential flow formation in no longer overbalanced and gas entry into the wellbore has started. After gas enters the wellbore, only gel strength development in the column can stop it from percolating to the top. Additives are available which assist “blocking” the gas bubbles from rising if the CSGS is below a value of 500 lbf/100 sq ft. Additives such as latex have been added to decrease the permeability of the slurry and make it more difficult for gas to propagate through the slurry. A CGSP time of 45 min or less is recommended by the API Standard 65, Part 2, in order to prevent gas breakthrough in those cases where sufficient OBP cannot be achieved when designing the cement job by working with the various other well parameters.

Obviously, the preferred design solution would be to have the CSGS value higher than 500 lbf/100 sq ft. This means that the setting cement would have a height above the potential flow zone that is somewhat less than the values in Figures 8-16 and 8-17. In this way the pressure next to the potential flow zone would stay above the formation fluid pressure until the cement was solid enough to prevent an influx. This is the ideal solution that the design of the job needs to target. The next two examples explain this suggestion.

8.10 Application of API Standard 65, Part 2

Good cement jobs can be difficult to obtain when a low OBP exists in a well because of a close margin between formation pressures and fracture pressure limits in the section being cased when a single slurry set time is developed for the lead and tail slurries. This section will demonstrate the difficulty with this procedure and then illustrate the benefits of a two-set-time cement slurry.

8.10.1 Single slurry cementing

Consider the situation illustrated in Figure 8-18. Production casing is installed in a 15,000-ft wellbore with a potential production zone at 14,500 ft. The pressure in the production zone is 12,064 psi or a 16.0-ppg mud weight equivalent. The lower section of the hole, from 13,000-15,000 ft was drilled with 16.5-ppg drilling fluid with a 6 ½-in. bit.

The hydrostatic pressure of the 16.5-ppg drilling fluid at 14,500 ft is 12,440 psi and the well will be cased with a 5-in.

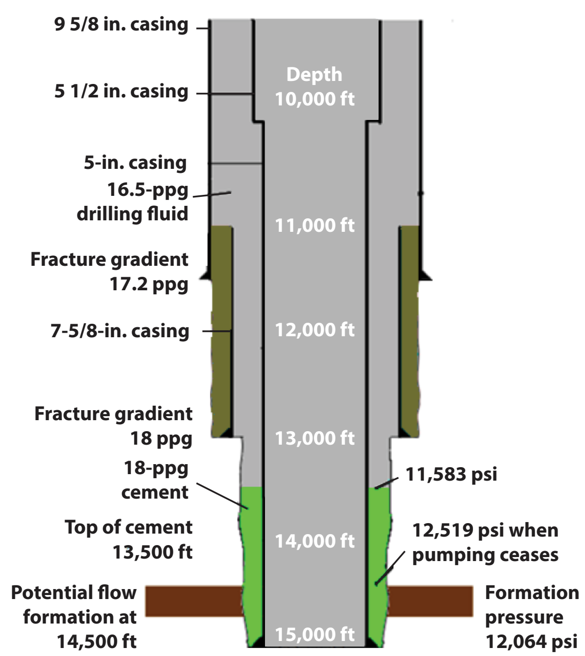


Figure 8-18: Schematic of the lower portion of a wellbore to be cemented with a single set-time slurry.

x 5 ½-in. full casing string. The casing will crossover to 5½ in. casing above the top of the 7 ⅝-in. protective liner and run to the surface. Cement will fill the annulus from 15,000 ft to 13,500 ft, leaving the 7 ⅝-in. casing shoe open. (The cement top is left below the 7 ⅝-in. casing shoe to avoid leaving trapped fluid in the annulus between the production casing and the protective string. Leaving the shoe open will avoid possible damage to the casing from annular fluid expansion due to changes in temperature when the well is put on production later. Trapped fluid expansion in a closed annulus can cause collapses of the production casing or burst in the outer string. The open shoe provides a leak-off point for the fluid to escape.)

What is the overbalance pressure at the 14,500-ft formation when the cement is first placed in the hole?

Drilling Fluid Gradient = 0.052 (16.5 ppg) (13,500 ft)
= 11,583 psi
Cement Gradient from 13,500 ft to 14,500 ft
= 0.052 (18 ppg) (1000ft) = 936 psi
Pressure at 14,500 ft = 11,583 psi + 936 psi = 12,519 psi
Formation pressure at 14,500 ft = 12,064 psi
Overbalance pressure = OBP = 12,519 psi – 12,064 psi
= 455 psi

What is the critical static gel strength (CSGS) at the potential flow formation at 14,500 ft?

$$CSGS = \frac{(OBP)\ (300)}{L/D_{eff}} \qquad \textbf{Equation 8-3}$$

OBP = 455psi
Cement column length, L = 1,000 ft
$D_{eff} = D_{oh} - D_c$ = 6.5 in. – 5 in. = 1.5 in.

Substitute values in Equation 8-3:

CSGS = (455 psi x 300) / (1,000 ft/1.5 in.) = 204 lbf/100 sq ft

The results of this equation indicate that the zone at 14,500 ft will just be at balance when the gel strength of the cement reaches a value of 204 lbf/100 sq ft. At this point, the column of cement above the potential flow zone at 14,500 ft will have lost the 455 psi of overbalance hydrostatic head. This creates a high risk for flow because the formation will reach a point of being underbalanced from the wellbore pressure when the gel strength of the cement is very low and incapable of preventing a gas influx from percolating through the unset cement. A minimum CSGS should be 500 lbf/100 sq ft, as discussed in API Standard 65.

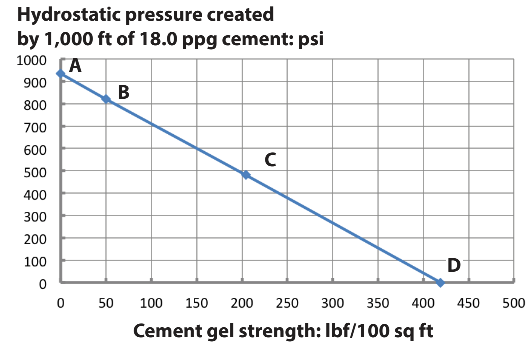


Figure 8-19: Contribution to the hydrostatic pressure at the potential flow zone from the 1,000-ft cement column as pressure decay occurs due to development of gel strength in the cement.

The data collected from the analysis above can be used to help describe the relationship that exists between the pressure decay and gel strength development in the cement column for the example well case (Figure 8-19). As the cement is placed in the well and starts to gel (or "set-up"), the pressure transmitted by the cement slurry decreases. When the cement is first pumped into the hole, and reaches placement depth and the pump stops, the effective gel strength at that instant is "0," when the cement column is a thin liquid. In this state, the cement will transmit full hydrostatic pressure through out the column just like any liquid. The hydrostatic pressure caused by the 1,000-ft column of 18-ppg cement will be 936 psi at the top of the potential flow formation at 14,500 ft, plotted as point "A" in Figure 8-19. The drilling fluid in the hole above the cement creates a hydrostatic pressure of 11,583 psi. The wellbore pressure adjacent to the potential flow formation is the sum of the hydrostatic pressure of both the mud and cement and is equal to 12,519 psi. The formation fluid pressure at 14,500 ft is 12,064 psi; therefore, the overbalance at the top of the formation is 455 psi when the pumps stop (12,519-12,064 psi). In the CSGS calculation above, the results indicate that the hydrostatic pressure of the cement column will decrease due to increasing gel strength to exactly balance the formation pressure when the gel strength of the cement reaches CSGS (204 lbf/100 sq ft). The hydrostatic pressure generated by the cement column above 14,500 ft will only be 481 psi when it exactly balances the formation pressure in the potential production zone. The original hydrostatic head of the cement column when placed was equal to 936 psi. The overbalance loss equals 455 psi. Therefore, the remaining head pressure after the gel strength reaches a value of 204 lbf/100 sq ft is 936 psi-455 psi = 481 psi, plotted as point C in Figure 8-19.

The formation pressure is 12,064 psi. The hydrostatic head created by the drilling fluid (11,583 psi) and the gelling cement (481 psi) will be 12,064 psi or equal to the formation fluid pressure. Any further decrease in wellbore pressure will cause formation fluid to enter the wellbore. As the cement continues to gel, the pressure will decrease to a lower value. This results in an influx of fluid from the zone at 14,500 ft. The gel strength of the cement at this time is only 204 lbf/100 sq ft and not sufficient to prevent gas from entering or rising in the wellbore. Any gas which enters the wellbore will percolate through the cement, leaving wormhole and open channels in the cement.

Connect points A and C (Point B will be discussed later) and then extend the line to intersect the horizontal gel strength axis. This line describes the relationship that exist between the gel strength of the slurry and the hydrostatic pressure contributed by the 1,000 ft column of cement above the potential flow zone at 14,500 ft. The pressure at the potential flow zone when the slurry reaches a given gel strength will be the sum of the cement column hydrostatic head and the mud column above the cement. The intersection of the pressure decay line at point D indicates that the column would no longer contribute any hydrostatic pressure once the gel strength has reached a value of 425 lbf/100 sq ft.

8.10.2 Summary

For a specific well the operational parameters are fixed values. The wellbore geometry, the formation pressures, the formation temperatures, the drilling fluid densities, the cement densities and the fluid column heights are specified and known. Once the cement is in place the contribution of hydrostatic pressure by the cement column will begin to diminish as the gel strength builds with time.

With the one slurry cement set time for the case just described, the cement slurry would not be able to prevent an influx of formation fluid into the wellbore. If the fluid is gas, or contains gas, the gas will create wormholes in the cement. Frequently, this is observed as annular pressure on producing wells. In a worse case scenario, it could also cause an underground blowout or worst.

8.11 Using two cement set times

Based on studies and field measurements of pressure behavior in the annulus of a well after cement flow ceases, the best method of preventing an influx is by controlling the rate of gel strength build-up and the set times of the cement, and limiting the free water in the cement slurry. The "tail slurry" cement at the bottom of the well and across the potential flow zone should set first while the cement above it is still fluid and able to contribute hydrostatic pressure to the formations below. After the lower tail interval sets and seals the potential flow zone, the upper interval (the lead slurry) just above the tail interval should then set. The temperature profile in the borehole must be known to properly tailor the cement set times to accomplish this objective. Several different set times may be necessary in a long cement sheath.

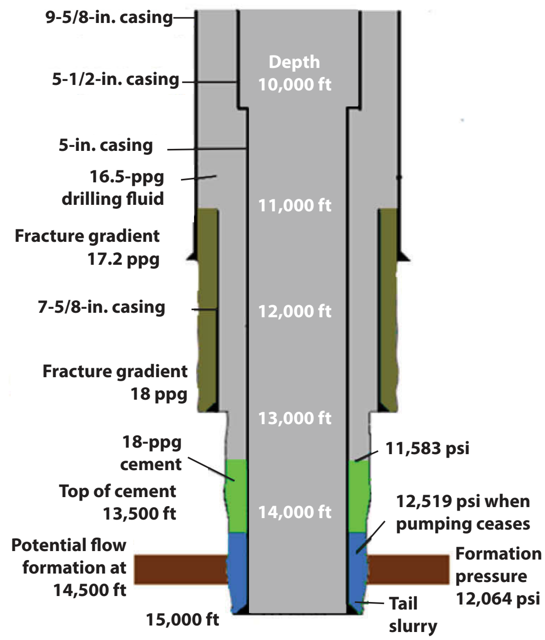


Figure 8-20: Two set times for cement.

As indicated in the example above, the pressure in the cement column will start decreasing as the cement begins to gel. If there is a permeable zone adjacent to the setting cement and the pressure in the formation is higher than the pressure in the wellbore, formation fluid will enter the wellbore if the cement has not set. When this happens the pressure in the cement where the gas enters will become equal to the formation fluid pressure and the gas will begin to rise up through the under- pressured and low gel strength cement column. In the past, attempts were made to place cement in an annulus using a single slurry where the bottom would be designed to set first without considering gel strength development time. As demonstrated in the calculation discussed above, this may not seal the annulus. The pumpability time of the top and bottom of the slurry was controlled but the gel strength development over time may have been the same.

8.11.1 Example case for designing a 2 slurry cement job

Using the analysis published in the API Standard 65, Part 2, cement slurries can be designed to prevent a formation fluid influx. Figure 8–20 depicts the same well configuration as the one used in Figure 8-18 for the single slurry example described above. In this situation, however, the design approach is modified so that the tail slurry will set while the lead slurry is still liquid (with a low gel strength) and can still provide sufficient hydrostatic pressure and pressure continuity from the mud above the cement to prevent an influx. This procedure is illustrated by the discussion below.

8.11.1.1 Application of API Standard 65 for cement gel strength

Using the same data , as shown in Figure 8-20:

- Drilled 6 ½-in. hole from 13,000 ft to 15,000 ft; gas formation at 14,500 ft;
- Pore pressure 12,064 psi (16.0-ppg equivalent mud weight);
- Drilled with 16.5-ppg mud weight; hydrostatic pressure at 14,500ft = 12,441 psi;
- Run and cement 5 ½-in. x 5-in. casing string; crossover at 11,200 ft. Fracture gradient at 7 ⅝-in casing shoe at 13,000 ft = 17.2 ppg.

Cement casing string with two cement slurry design. The 18.0-ppg tail slurry will be designed to quickly develop sufficient gel strength to prevent gas from entering the wellbore. The 18-ppg lead slurry (above the tail slurry) will be designed to allow it to remain liquid with a controlled gel strength and still able to maintain hydrostatic pressure at the top of the tail slurry until after it has developed the strength to seal the potential flow zone.

Design the tail slurry to be placed from TD (15,000 ft) to 14,200 ft, or 300 ft above the potential flow zone. The total height for the combined two slurry cement column above the potential flow zone is the same (1,000 ft) as the cement column in the single slurry case above.

Designing the height of the early set tail slurry to be only 300 ft above the flow zone will be enough cement to provide an early barrier above the flow zone. Selecting the short height of the tail slurry above the flow zone also allows for a longer lead cement slurry column above to maximize the overbalanced pressure provided by the combination of the drilling fluid column and the low gel strength lead cement slurry. The impact of making this choice is evident from an analysis of the CSGS using Equation 8-3:

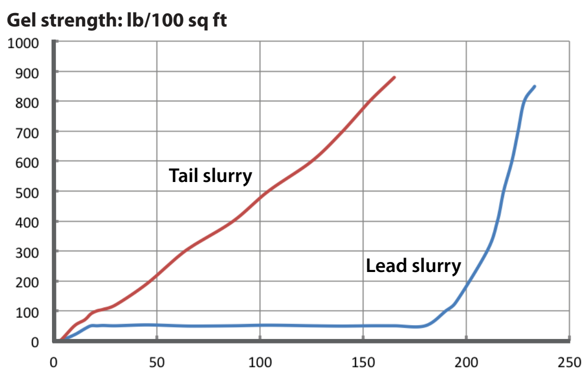


Figure 8-21: Gel strength development in the lead and tail cement slurries.

$$CSGS = \frac{(OBP)\ (300)}{L/D_{eff}}$$ **Equation 8-3**

A higher overbalance pressure from a longer column of lead cement and a shorter column of early setting tail cement above the potential flow zone will result in a higher CSGS. This is possible because the slowly developing gel strength cement above the tail slurry will behave almost like a thick drilling fluid. The lead slurry will provide hydrostatic pressure support to the top of the tail slurry well beyond the time when the tail slurry has set and isolated the potential problem zone. After the lead slurry sets the combination of the tail and lead slurries together will provide added height to the cement barrier above the potential flow zone.

To accomplish the desired objectives, the composition design of the two cement slurries must be developed in the laboratory. The tail slurry must set first while the lead slurry can still provide sufficient hydrostatic pressure to maintain an overbalance condition at the potential flow zone as shown on Figure 8-21.

The time of the gel strength development of the two slurries must be measured under downhole temperature and pressure conditions. These conditions must duplicate the conditions in the well to be cemented.

The test data shown in Figure 8-21 represents the gel strength development vs. time results of two slurries designed in the lab to be used for the well case being considered. The data indicates that the tail slurry will build a quick and steady gel strength of 500 lbf/100 sq ft at about 105 min after placement. The lead slurry builds a gel strength of 50 lbf/100 sq ft in about 18 min which then remains constant for about 180 min. This is well past the 105 min required for the tail slurry to build enough gel strength to prevent gas entry into the wellbore. The lead slurry begins to set quickly after 180 min.

8.11.2 Calculating the overbalance pressure in the potential flow formation when the gel strength of the cement opposite the zone reaches 500 lbf/ 100 sq ft

Will these two slurries meet the desired quantitative objective for cementing the example well discussed above? This needs to be verified by calculating the pressures in the annulus adjacent to the potential flow zone when the cement across the formation has reached sufficient gel strength to prevent gas percolation.. The pressure will be the sum of the hydrostatic pressure exerted by the drilling fluid column, the lead slurry and the tail slurry. Refer to Figure 8-20.

Calculate the hydrostatic pressure at the top of the tail slurry (14,200 ft) provided by the drilling fluid column and the lead slurry of cement at the time when the tail slurry reaches a

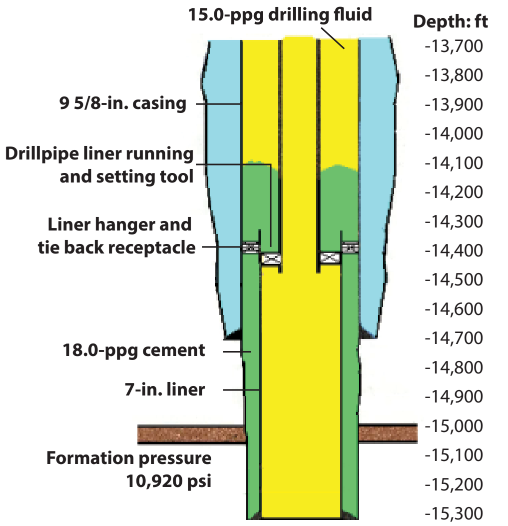


Figure 8-22: Completion liner in well in 4,000 ft of water, just after plug bumped.

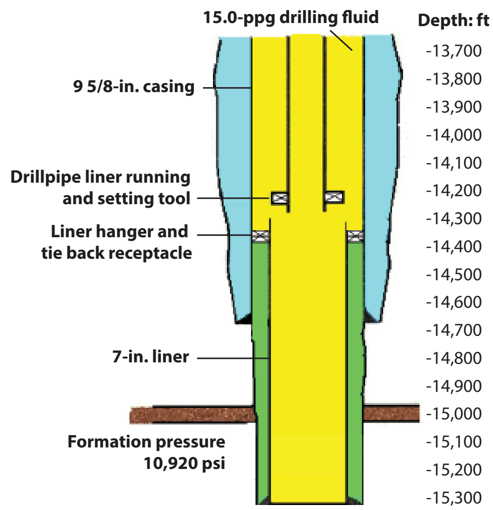


Figure 8-23: Completion liner in well in 4,000 ft of water after reversing out excess cement.

gel strength of 500 lbf/100 sq ft. This would be 105 min after the cement is placed in the well, as shown in Figure 8-21. The drilling fluid column would provide a hydrostatic pressure of [0.052 (16.5 ppg) (13,500 ft)] or 11,583 psi. Next, calculate the pressure contribution of the lead cement column below the drilling fluid. Refer to Figure 8-19, which indicates that a 1,000 ft column of 18-ppg cement placed in this well with a 50 lbf/100 sq ft gel strength would provide a hydrostatic pressure of 820 psi (Point B), or 0.82 psi/ft of cement column. This means that the 700 ft of 18.0-ppg lead cement (from 13,500-14,200 ft) would provide a pressure of 0.82 psi/ft or 574 psi. Since the 16.5-ppg drilling fluid is above the lead cement, then the pressure at the top of the tail cement after 105 min would be the sum of the mud and cement head combined, calculated as 11,583 psi + 574 psi or 12,157 psi.

Since the formation pressure is 12,060 psi, there should be no influx of formation fluid into the annulus of this well even when the short height of the tail slurry below the bottom of the lead slurry down to the potential flow zone has developed high gel strength and is not contributing very much hydrostatic pressure to the column. The column pressure of the drilling fluid and lead cement provide a net differential pressure of 93 psi above the potential flow zone pressure and should prevent fluid from entering the wellbore. Additionally, at this time the static gel strength of the tail cement has reached 500 lbf/100 sq ft and, if gas did enter the wellbore, it would not percolate through the cement.

8.11.3 Summary

The two different cementing procedures just discussed were applied to the same wellbore configuration to illustrate the need for two different set times when the cement is placed in the annulus. The same cement and drilling fluid densities and the same depths were used in the discussion to clearly illustrate that a 1,000-ft column of a one- setting time cement slurry in the annulus between a 5-in. casing and a 6 ½-in. wellbore would not prevent an influx of formation fluid into the wellbore. The maximum length of a column of cement needed to prevent formation fluid intrusion depends upon the initial over balanced pressure, and the effective diameter (hole diameter minus casing diameter), as shown in Figures 8-16 and 8-17. The pressure decay for a given well and cement column is a function of the gel strength development in the cement. The hydrostatic pressure that a column of cement can exert at a given time depends upon the gel strength at that time.

8.12 Production liner in deepwater example

An offshore well being drilled in 4,000 ft of water has a production horizon at 15,000 ft, with a formation fluid pressure of 10,920 psi (14-ppg equivalent mud weight). A 9 ⅝-in. combination protective/production casing is set at 14,700 ft and the casing seat seal verified (good PIT at 17.0 ppg at 14,700 ft). An 8 ½-in. hole is drilled through the pay zone to a depth of 15,300 ft with a 15.0-ppg drilling fluid. A rotating liner hanger with a tie-back receptacle, but without an integral packer (open annulus between the liner and casing), will be used to hang and cement the 900-ft, 7-in. liner so that there is a 300-ft overlap in the 9 ⅝-in. production casing. The 7-in. liner will be run in the well with a drill string and a rotating running and setting tool. An 18-ppg cement will fill the annulus behind the liner and is designed to allow for excess volume to be pumped past the liner top to help improve cement sweep efficiency (Figure 8-22).

After the cement is in place and the plug bumps, the running tools can be pulled to the top of the hanger and the small amount of contaminated excess cement above the liner can be reversed out of the well. This will leave a clean liner top and a 600-ft head of cement in the annulus above the production zone to the top of the liner (Figure 8-23).

The pressure in the annulus adjacent to the production zone when cement pumping ceases is the pressure of a 14,400 ft column of 15 ppg drilling fluid plus the pressure from the hydrostatic head of the 600 ft of cement. (0.052) (15 ppg) (14,400 ft) + (0.052) (18 ppg) (600 ft)= 11,232 psi + 561 psi = 11,793 psi. The pressure in the formation is 10,920 psi. The overbalanced pressure (OBP) as the cement starts to gel is 11,793 psi – 10,920 psi = 873 psi.

The next step is to calculate the CSGS results for the liner cementing operation to determine whether an overbalanced pressure can be maintained on the producing zone from the time the cement is placed in the well until it has developed enough gel strength to prevent a well influx when using a single slurry design.

The CSGS for this situation can be calculated from Equation 8-3:

$$\text{CSGS} = \frac{(\text{OBP})\ (300)}{\text{L/D}_{\text{eff}}}$$ **Equation 8-3**

Where:

OBP = 873 psi
L = 600ft
D = 8.5 in. – 7 in. = 1.5 in.

$$\text{CSGS} = \frac{(873\text{ psi})\ (300)}{600\text{ ft}/1.5\text{ in.}_{\text{eff}}} = 655\ \frac{\text{lb}}{100\text{ sq ft}}$$

This means that the gel strength in this slurry will be sufficient to prevent an influx from the potential flow zone as the pressure in the wellbore due to cement gelation decreases to equal the open formation's pore pressure. The cement slurry should be blended so that it progresses from 100 lbf/100 sq ft to 500 lbf/100 sq ft gel strength in around 45 min. In reality for this case, since CSGS is higher than 500 lbf/100 sq ft, it does not matter how long it takes it to get to 500 or 655 lbf/100 sq ft because the column pressure will exceed the pressure of the potential flow zone past the time when the gel strength reached the 500 lbf/100 sq ft value. The critical gel strength period, CGSP, is only important when the CSGS value is lower than 500 lbf/100sqftwhen hydrostatic pressure goes below formation pressure before the cement has the gel strength to prevent percolation of gas.

8.12.1 Operation sequence after reversing excess cement from top of the liner

As discussed earlier, after the cement is in place and the plug has landed the end of the setting tools is simply pulled to the top of the rotating liner hanger, and excess cement is reverse circulated out of the well to clear the top of the liner. (The setting tools were disconnected and free from the hanger after it was set. The rotation of the liner and the cement job were conducted via a spline and pack-off system without an actual joined connection between the setting tools and the hanger. This ensures that the tools can be pulled out of the hanger without having to perform any special maneuver to release the tools from the liner after cement is in place.) After cleaning the top of the liner, the running string and setting tools should then be pulled up an additional 300 ft-plus to ensure there is no cement surrounding the setting tools. The well can be shut-in with +/- 100 psi and the setting string can serve to monitor the well as the cement sets. The cement can be pressure tested both ways using the running string after it has set to confirm a good seal before pulling out of the hole. The greatest advantage of using a liner instead of a full string is the fact that the annulus can be observed above the production zone while keeping a kill string immediately above it. The advantage of using a liner is also the fact that the casing can be rotated while cement is flowing in the annulus. Frequently, long strings of casing cannot be rotated from the surface and poor cement seals can result.

8.13 Operational suggestions

8.13.1 Use a blender to mix small volumes of cement

Frequently, the volume of cement needed for liners is relatively small. A more uniform homogeneous slurry can be obtained if it is mixed in a blender before it is pumped downhole.

8.13.2 Use low fluid loss cements with low mix water ratio

Tests have indicated that a lower mix water ratio (36% vol.) and a lower fluid-loss cement slurry (less than 50 cc/30 min) tends to reduce the loss of head in the column when compared to cement slurries with 46% vol. mix water ratios and fluid losses greater than 100 cc/30 min.

8.13.3 Large OBP facilitates well design

This was an easy example because the OBP was so large. This is often not the case when setting a liner because the open hole shoe of the section being cemented is weak and the mud weight is only slightly higher than at the highest pressured formation in the well. When lower OBP exists, CGSP becomes more important to preventing gas percolation through the cement until a seal can be achieved. In these cases maintaining the monitoring kill string in the hole becomes a great asset that can be used to pump into the well or to circulate it dead.

8.13.4 Determining liner overlap requirements

In the real world, 300 ft of liner overlaps used in this example is adequate to accomplish a barrier and using more than that is really a waste. It is fairly easy to get a seal between concentric and centered casing strings when the liner can be rotated. The strings have very good standoff because the rotating liner hanger serves as a very strong centralizer.

8.13.5 Annular gas flow after cementing operations

After satisfactory cementing a long string of casing and checking for a good seal of formations, gas can start to flow up the annulus as long as one month after the well was properly sealed. Garcia and Clark, in 1976 reported using a noise log to find no flow immediately after the initial set of the cement, and then,flow behind casing later during the life of a well. When the well starts production, stress changes in the casing and in the cement can cause each to change dimensions. The stress changes could be caused by temperature changes as well as pressure changes in the well. This can create a pathway for gas, or formation fluids, to enter the annulus and flow into a lower pressure formation.

8.14 Authors' note

In this chapter, the approach to the prevention of gas influx after cementing has been presented in what might be called "a creative thinking process of learning." Using the two different scenarios in the illustrations above should make it easier for a first time user to understand the concepts presented so they can be more easily applied the right way to real well situations. Understanding the concept of how the gel strength controls hydrostatic pressure and the concept of the gel strength preventing gas percolation through the setting cement will also allow better well designs. The equations might explain the solution to the problem; but understanding the physics behind the solutions will assist in easier applications to real field problems.

Appendix 8A: Analysis of critical static gel strength equation

API Standard 65, Part 2, uses an empirical equation to calculate the Critical static gel strength (CSGS). CSGS is defined as the static gel strength of cement that results in the decay of hydrostatic pressure to the point that pressure is balanced across the potential flowing formation.

$$CSGS = \frac{(OBP)\,(300)}{L/D_{eff}} \qquad \textbf{Equation 8A-1}$$

Where:

CSGS is the critical static gel strength, lbf/100 sq ft

OBP is the overbalanced pressure in psi

300 is a unit conversion factor and an empirical constant

L is the length of the cement column above the flow zone, ft

D_{eff} is the effective diameter (in.) and is the difference in diameters between the open hole and the casing

The denominator in Equation 8A -1 is a geometric factor and is the ratio of the "slot width" to the length of cement column. The slot width is the difference between the radius of the open hole(R_{OH}) and the casing (R_c).

$$\text{Slot width} = R_{OH} - R_C = ½\,[D_{OH} - D_C] = ½\,D_{eff} \qquad \textbf{Equation 8A-2}$$

The units of the right side of Equation 8A-1 must be modified to calculate the value of CSGS in pounds per hundred square feet.

$$CSGS = \frac{\left(OBP\ \frac{lb}{in.^2}\right)\left(\frac{144\ in.^2}{sq\ ft}\right)}{\dfrac{(L\ ft)\left(\frac{12\ in.}{ft}\right)}{\frac{D_{eff}\ in.}{2}}} \qquad \textbf{Equation 8A-3}$$

Converting the units to produce the value of CSGS in lb/100 sq ft produces Equation 8A-4:

$$CSGS = \frac{\left(OBP\ \frac{lb}{in.^2}\right)(600)}{\dfrac{(L\ ft)}{D_{eff}\ in.}} \qquad \textbf{Equation 8A-4}$$

The committee obviously wished to be conservative and decreased the "600" unit changing constant to "300", resulting in Equation 8A-3.

Chapter 9
Pressure Integrity Tests

TABLE OF CONTENTS

9.1 INTRODUCTION

After casing is cemented in place, the casing and casing seat is tested to validate a successful cement seal and determine the strength of the formation at the casing seat. This chapter is presented to provide some guidelines to help understand some of the technology behind the pressure integrity test (PIT) process.

9.2 Equipment used to test casing and cement job

After cementing casing, a drill bit is normally run in the hole to smooth the top of the cement left in the casing. After circulating "bottoms-up", the blowout preventer is closed and pressure applied to the drillpipe. The mud weight in the well pipe must be the same from top to bottom. The pressure measured at the top in the drillpipe will be added to the bottomhole pressure to determine the casing integrity and the formation strength. If the liquid does not have the same density throughout the column, the pressure cannot be determined. The drilling fluid surface processing plant should have sufficient capacity in the suction section to ensure that the drilling fluid density is the same from top to bottom in the drill string.

Pressure cannot be transmitted through a gelled drilling fluid. Pressure is transmitted undiminished throughout a liquid but not a gelled fluid. The drilling fluid used for these tests must have a gel strength as low as possible. Some gel structure is of course needed to suspend barite in a weighted drilling fluid; but it should be as low as possible. Also, gel strength tends to increase with time while the drilling fluid is not moving. These tests should be completed as soon as possible after the drilling fluid ceases to move.

The plumbing and equipment in Figure 9-1 is arranged so that the air can be removed from the system before pumping drilling fluid down the drillpipe. The pressure gauge must be calibrated properly for the test. While pumping fluid into the drillpipe, the pressure is read and plotted on graph paper every one-fourth of a barrel or every minute.

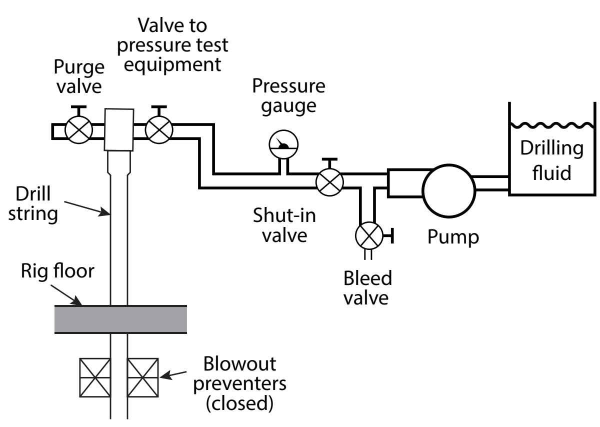


Figure 9-1: Plumbing suggested for the PIT(pressure Integrity test) or LOT (leak-off test).

9.2.1 Cement pump unit

A high-pressure, low-volume positive displacement pump is needed to pump the fluid. A cement unit pump fulfills this requirement. Rig pumps generally cannot maintain a constant low-flow rate speed.

9.2.2 Circulation sub

A special circulation head treads into the drillpipe similar to a cementing head. The head should have at least two ports with hammer-union connections.

9.2.3 Shut-in valve

A shut-in valve is installed between the pump and pressure gauge.

9.2.4 Bleed valve

Between the shut-in valve and the pump, a bleed valve is installed. This is used to check for leaks of the shut-in valve during the test. A leaky valve would indicate a poor cement job (no seal around the casing shoe) and result in an unnecessary squeeze job. This valve could also be used to bleed the pressure from the drillpipe after the test.

9.2.5 Purge valve

Air must be removed from the system to prevent misinterpretation of the pressure readings. After all of the lines are connected to the test circulation sub on top of the drillpipe, all of the air is displaced from the lines before the PIT.

9.2.6 Pressure gauges

Inaccurate gauges or gauges with the wrong scale range can make the PIT plot very difficult to interpret and even create incorrect results. The pressure gauge should be calibrated and used only for the PIT. Hard to read gauges may produce errors as large as 50 psi. Gauges should meet the following guidelines:

9.2.6.1 Type: liquid-filled, 4-in. diameter or larger

A liquid-filled gauge gives a smoother response to pressure changes than a dry gauge. The liquid dampens the pump pressure surges. Gauges smaller than 4 in. in diameter are difficult to read and frequently have increments between marks that are too large. A pulsation dampener between the gauge and the test line will also improve the readability.

9.2.6.2 Range: As low as possible

The gauge range should be 25-50% greater than the maximum anticipated PIT pressure. The smaller the range, the better.

To determine the correct range, multiply the anticipated maximum PIT pressure by 1.25. Choose the smallest range that exceeds this value. For example, if the maximum test pressure will be around 1000 psi, choose a gauge with at least a 1,250 psi maximum reading. A 1,500 psi gauge will probably be the smallest available to meet this criterion.

9.2.6.3 Smaller pressure increments are better

For gauges reading a maximum of 2,000 psi or less, the dial increment should be 25 psi or less. For pressure ranges above 2,000 psi, increments should be 50 psi or less.

9.2.6.4 Location: isolated from pump vibrations and pressure surges

Do not mount the test gauge directly on the metal pipe from the pump to the drillpipe. Connect the gauge to the test line with at least a 5-ft piece of flexible pressure hose. If possible, connect the pressure gauge near the displacement tank or the pump stroke counter so that both the pressure and the volume can be monitored simultaneously.

9.3 Procedure

The following steps assume the new bit on bottom drilling or washing down to the float collar.

9.3.1 Calibrate the pump

Do not assume the mechanical counter on the pump is accurate. Monitor the volume displacement from the suction tanks. The displacement tanks should be marked for every ¼ bbl. Be certain that the drilling fluid is free of air or gas. If not, account for the amount of air in the volume pumped. If the pump stroke counter must be used, pump stoke/volume calibration should be performed before the PIT. A known volume of fluid must be pumped under about the same pressure as the test and the time for the volume measured.

9.3.2 Set-up procedures before running PIT

9.3.2.1 Pressure test the entire surface system up to the drillpipe before the PIT

The test pressure should be greater than the maximum anticipated PIT pressure. Monitor the annulus above the closed blowout preventer during the test. Peculiar leak-off pressures during shut-in are often traced to leaking test lines or leaking BOP.

9.3.2.2 Circulate at least one well volume before pressure testing the casing

This is a safety feature to determine if a kick has entered the casing.

9.3.2.3 Fill the drillpipe with a homogeneous fluid before testing the casing

The fluid must have the same density at all depths in the drillpipe — just like the requirement for well control procedures. The pressure at the bottom of the well will be the sum of the pressure created by the mud weight in the drill string and the applied pressure. The pressure applied to the top of the drill string will be transmitted to the bottom of the drill string ONLY if the gel structure of the drilling fluid is relatively low. If the drillpipe is filled with a highly gelled drilling fluid, the pressure at the bottom of the pipe may not increase when the pumps apply pressure to the top. See the discussion of the mud tank arrangements (Chapter 12) to have a homogeneous density in the drillpipe.

9.3.2.4 Reverse circulation can create many problems: Pump fluid down the drillpipe

The drilling fluid in the drillpipe is more likely to be free of gelation and solids than the drilling fluid in the annulus. A better indication of bottomhole pressure is determined through the drillpipe — just as stated in the Well Control procedures.

9.3.2.5 Any leak in the casing should be addressed and sealed before drilling the cement shoe

If no leaks are found, drill the float collars and slowly drill about five to ten feet of new formation. Circulate the wellbore clean. The drilling fluid left on bottom should have a very low fluid loss and preferably no drilled solids. Consider spotting a clean new drilling fluid from the slug tank in the open hole. As this fluid is being placed on bottom, the hole could be slowly reamed to remove any poor quality filter cake. The fluid should also have a relatively low gel structure to insure that the pressure applied to the top of the drillpipe is also applied to the formation at the bottom of the hole. If the drilling fluid in the new hole has a high gel structure, the pressure may not be transmitted throughout the open hole. This is similar to the concerns about holding a "back pressure" on cement when it is setting. This is not a good idea because the pressure does not transmit well through a gelled slurry.

9.3.3 Pump rate

The slower and the steadier the pump rate, the better the chance for developing interpretable data. Faster pump rates can hide the leak-off point. Unsteady pump rates will confuse the interpretation because the initial part of the PIT curve will not be a straight line. For impermeable formations, a rate of ¼ bbl/min should be used. For permeable formations the rate may have to be increased to ½ bbl/min or more to overcome filtration losses. Do not exceed one bbl/min because high pump rates will give erroneously high leak-off pressures. Fracture initiation pressure is related to the rate at which the pressure is applied. The higher the rate the higher the fracture initiation pressure.

The "true" leak-off pressure is the pressure determined at the lowest practical pump rate. The lowest practical pump rate is the lowest rate that will overcome filtration losses.

Use the maximum volume line as a guide to determine if a higher pump rate is needed. After half of the maximum expected volume has been pumped, compare the plotted

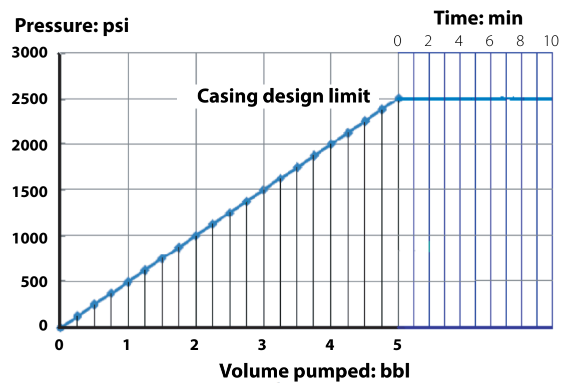


Figure 9-2: Pressure-testing the casing before drilling the shoe.

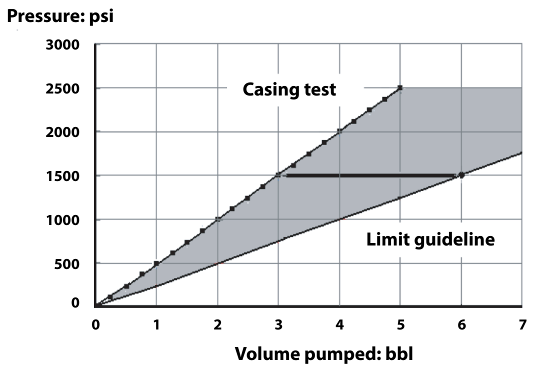


Figure 9-3: Pressure vs volume pumped chart showing the limit guideline.

data with the maximum volume line. If the data is not above this line, shut off the pump, bleed the pressure to zero, and retest. This time use a pump rate 1/4 bbl/min higher than the previous test. In any event do not exceed 1 bbl/min.

9.3.4 Shut-in period

At the end of the test (when the pressure ceases to increase in a linear manner), the shut-in valve is closed and the pressure is read every minute for at least ten minutes. Occasionally, the shut-in valve leaks and it appears that the cement around the shoe is not an effective seal. A bleed valve between the pump and shut-in valve is opened when the shut-in valve is closed. Any leakage may be observed easily to prevent an unnecessary squeeze job. Usually, a bucket is placed beneath the bleed valve to capture any fluid which does drain back through the shut-in valve.

9.4 Casing test

After cementing a string of casing, a drill bit is run into the hole to the top of the cement inside of the casing. The blowout preventer is closed and pressure applied slowly to the drilling fluid inside of the drill string. This pressure tests the casing to ensure that all connections are properly sealed. The pressure is plotted on a graph as a function of either time or volume of fluid pumped. Obviously, the system should be completely sealed; consequently, the pressure should increase linearly with the volume injected into the system. The casing will expand slightly but the pressure should increase quite rapidly as indicated in Figure 9-2.

As each one-fourth of a barrel is pumped, the surface pressure indicates that it is increasing linearly. This indicates there are no leaks at any of the connections. If there is a leak, the pressure will not increase along a straight line while pumping slowly. After the casing design pressure limit is reached and the pressure increase has been a straight line, pressure is maintained for five to ten minutes to confirm that there is no leak. If the pressure does not remain constant, the leak needs to be repaired before drilling the shoe or completing the well if this is the production string.

9.5 Pressure integrity test

After testing the casing, the float collar is drilled and the formation about five to ten feet below the shoe is drilled. This test is designed to determine if the cement sealed the casing annulus and to determine the fracture pressure of the formation below the casing. With the drillpipe pulled back up inside of the casing, the blowout preventers are closed and pressure is applied at the upper end of the drill string. A chart should be prepared ahead of time so that the pressure can be plotted during the test. Again, either the volume pumped or the time is labeled on the horizontal axis and the pressure is plotted on the vertical axis. Experience has shown that most good tests result in the pressure being below the casing pressure test line and twice that value. A line may be drawn from the origin through twice the time or volume pumped, as shown in Figure 9-3.

In Figure 9-3, the casing pressure test line indicated three barrels of fluid were pumped creating a pressure of 1,500 psi. Thus, the limit guideline would be six barrels pumped at a pressure of 1500 psi. The pressure test data for the open hole should usually be between these two lines or within the shaded area in Figure 9-3.

As fluid is pumped into the wellbore, the pressure increase should be a linear function (or a straight line) with time or volume pumped. In Figure 9-4, the line was reasonably straight until four barrels had been pumped. The bend in the curve indicated that a crack was formed in the formation just drilled. After pumping another three-fourths of a barrel of fluid, the deviation from a straight line was validated and the pumps stopped. The pressure on the drillpipe immediately decreased to 1,500 psi. The decrease in pressure is caused by the loss of pressure drop in the crack created around the wellbore by the drilling fluid. The 1,500-psi pressure reading is called the instantaneous shut-in pressure.

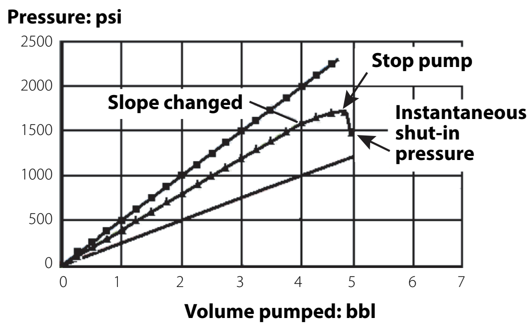


Figure 9-4: Pressure testing the casing seat.

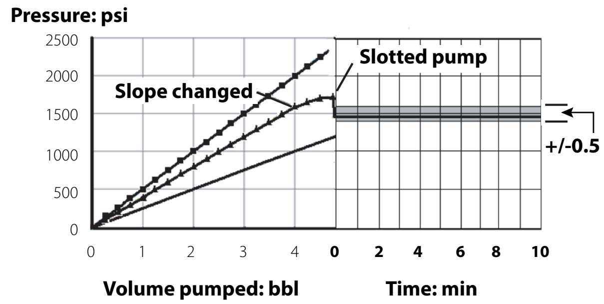


Figure 9-6: Range of expected fracture gradient.

9.5.1 Interpretation of pressure readings

What happens next is crucial to understanding the meaning of the pressure integrity test (PIT).

9.5.1.1 Constant pressure after shut-in

If the pressure stays constant for the next ten minutes, the cement around the casing shoe is not leaking and the formation is impermeable (Figure 9-5).

The pressure of about 1,480 psi indicates the pressure in the wellbore as the fracture closes when the pump was stopped. This would indicate the lowest tectonic stress in the area around the wellbore. The breakdown stress (where the slope changed) must be higher than this stress. Rocks are very weak in tension and strong in compression. The primary stress preventing the rock from fracturing is the tectonic stress within the rock. When a fracture is created, the pressure in the fracture must be higher than the stress holding the rock together. In this case, the lowest stress holding the rock together is the 1,480 psi plus the pressure caused by the mud weight.

The test shown in Figure 9-6 represented a good cement job for a 7,200-ft casing shoe with a 13.0-ppg drilling fluid. The predicted fracture gradient was a 17.0-ppg equivalent mud weight. Normally, the predicted fracture gradient, plus or minus one-half pound per gallon, is drawn on the chart before the test. The pressure caused by a 13.0-ppg drilling fluid at 7,200 ft would be:

Pressure = 0.052 (mud weight, ppg) (depth, ft)
Pressure = 0.052 (13.0 ppg) (7,200 ft) = 4,870 psi

The pressure required to break the rock (create a fracture) for the 17.0-ppg drilling fluid would be:

Pressure = 0.052 (17.0 ppg) (7,200 ft) = 6,360 psi

To create the effect of the 17.0-ppg drilling fluid, the pressure which must be applied is:

Pressure = 6,360 psi – 4,870 psi = 1,490 psi

The uncertainly of plus or minus one-half pound per gallon would be equivalent to a pressure variation of:

Pressure = 0.052 (0.50 ppg) (7,200 ft) = 190 psi

The shut-in pressure was within the anticipated pressure to indicate a 17.0-ppg fracture gradient. In this case, the casing seat was set in a very impermeable shale and the cement has sealed around the casing shoe.

9.5.1.2: Pressure decreases after shut-in indicating a poor cement job

If the pressure applied to the casing seat slowly disappears, the drilling fluid is probably flowing up the annulus. If the pump is stopped and the pressure decreases to an anticipated value, the integrity of the casing/cement job has not been validated. In Figure 9-7, the pressure increased as

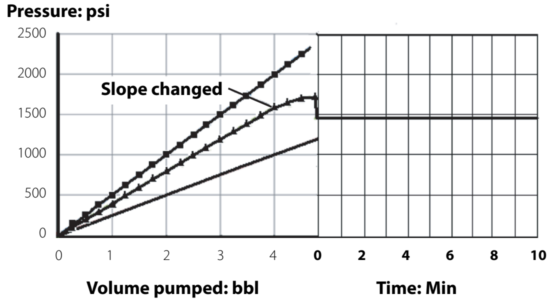


Figure 9-5: Observing the pressure after stopping the pumps.

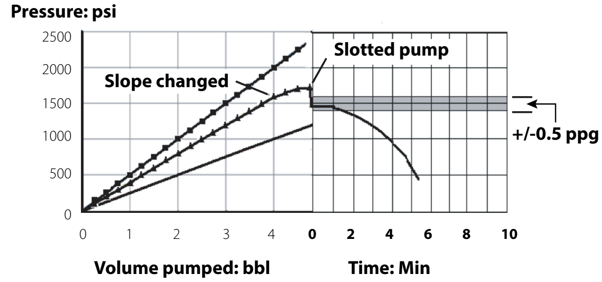


Figure 9-7: Bad cement job.

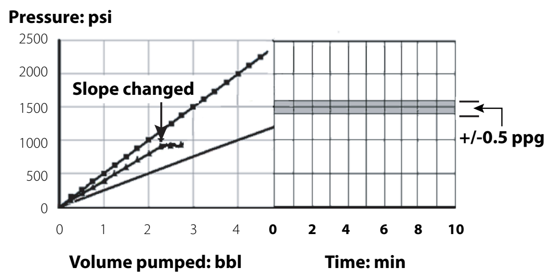


Figure 9-8: Early slope change.

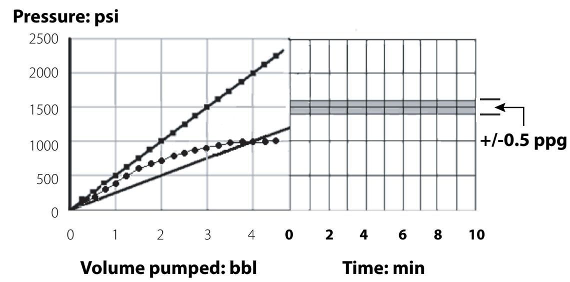


Figure 9-10: Testing a permeable casing seat.

anticipated. When the pump was stopped after the slope changed, the pressure dropped to the expected instantaneous shut-in pressure. After about one minute, however, the pressure started decreasing. Possibly some channels in the cement were filled with gelled drilling fluid and took a minute or so to be displaced from the channels. In this case, a cement squeeze is highly recommended.

9.5.1.3 False indicator of formation breakdown

After about two barrels had been pumped, the pressure curve indicates a large slope change (Figure 9-8). The pressure is too low to indicate a good cement job, so the next step must be decided upon. If the test is terminated at this point, a squeeze job is required. However, if a squeeze job is required, continuing to pump will not create any more damage. Frequently, a gas bubble in the system or other events take place which cause the failure of the pressure line to continue to be a straight line (or a linear relationship).

When pumping continued, the pressure curve moved steadily upward in linear fashion, i.e., a straight line (Figure 9-9). The next question becomes: "Was the first slope change caused by a leak-off?" The horizontal line indicates the pressure at the bottom of the well after the fracture closes. A pressure slightly larger than this pressure is required to open a fracture. Any perturbations from a straight line at a pressure below the fracture pressure can be ignored because it would not be possible to open a fracture without applying a stress larger than the lowest stress holding the rock together.

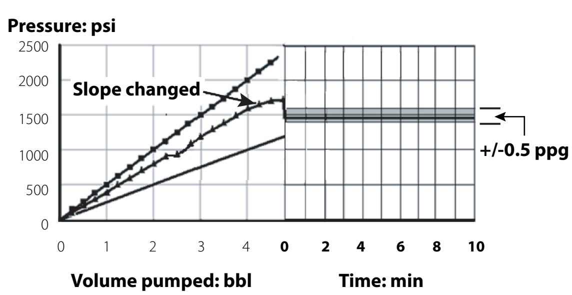


Figure 9-9: Continuing to pump after an early slope change.

9.5.1.4 Casing seat set in a permeable formation

When filtration occurs in the new hole drilled below the casing seat, the standpipe pressure will not increase in a linear (or straight line) manner (Figure 9-11).

The system is leaking fluid from the wellbore. Insufficient pressure is being applied to find the strength of the formation because the fluid loss is too great. If the fluid loss is not too much, the pump rate during the PIT can be increased to about one-half barrel per minute. This requires an understanding that the leak-off pressure can be artificially raised by increasing the pump rate even when the newly drilled hole is in an impermeable rock. The fluid is probably going into a permeable formation. This is the reason a good low-fluid-loss drilling fluid should be placed inside of the new hole. This drilling fluid should be completely free of drilled solids so that the filter cake will be as thin and impermeable as possible. The fluid is probably going into a permeable formation. This is the reason a good low-fluid-loss drilling fluid should be placed inside the new hole. This drilling fluid should be completely free of drilled solids so that the filter cake will be as thin and impermeable as possible.

9.5.1.5 Poor cement seal at shoe

When the pressure continues to decrease with additional pumping, the cement has failed to seal the annulus from the new hole (Figure 9-11). A cement squeeze job is required. Additional cement must be spotted on the bottom of the hole and pressure applied to move the cement into the areas that are not sealed.

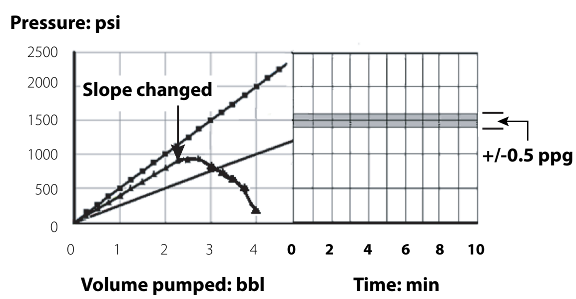


Figure 9-11: Poor cement job.

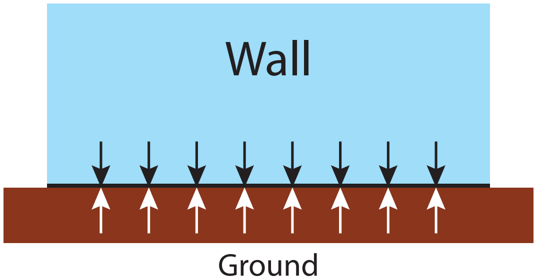


Figure 9-12: Stresses — or pressure — at the bottom of the wall.

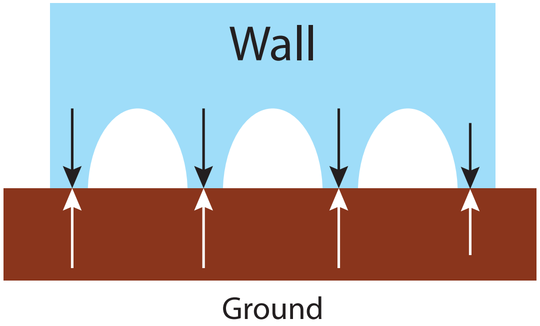


Figure 9-13: The columns each now exert a higher force on the ground in order to continue to support the wall.

9.6 Bad choices for increasing pressure readings

9.6.1 Some recommend placing a gelled drilling fluid on bottom

The pressure at the surface will not be transmitted to the open hole through the gelled drilling fluid. Pressure is transmitted undiminished through a liquid or a gas. However, when a drilling fluid starts gelling, the pressure is no longer transmitted undiminished. One way to explain this is to consider Poisson's Ratio. The horizontal stresses in a formation depend upon the overburden stress and the Poisson's Ratio:

$$\sigma_h = \frac{v}{(1-v)} \sigma_v \qquad \textbf{Equation 9-1}$$

Where:

- σ_h is the horizontal stress
- σ_v Is the vertical stress
- v is Poisson's Ratio

For water, Poisson's Ratio is 0.5, which means the horizontal stress is the same as the vertical stress. For a soft formation or a gelled fluid, the Poisson's Ratio might be 0.4, which means the horizontal stress will only be 2/3 of the vertical stress.

9.6.2 Others recommend including calcium carbonate to seal the formation

The concept of sealing is correct but a thin, impermeable filter cake is needed. Mix a new batch of drilling fluid in a slug tank and add sufficient filtration additives to greatly reduce the fluid loss. New drilling fluid is needed to eliminate any drilled solids which will increase the fluid loss down hole. Spot this new drilling fluid on bottom and repeat the PIT. Make certain that the density of the new fluid is exactly the same as the density of the rest of the system.

9.6.3 The leak-off pressure must be larger than the minimum stress required to open a crack

In the case of the PIT the stress required to open the crack is the same as the stress just before the crack closes. If the pressure/volume curve has several apparent discontinuities, many can be dismissed because they are smaller than the closure stress indicated during shut-in.

9.6.4 When there is some question concerning the authenticity of the leak-off value, repeat the PIT

In some more complicated situations, a second PIT clarifies the value. For example, if gelled drilling fluid plugs leaks in the cement sheath, the first PIT can remove the gelled plug and the second PIT leaves no doubt that the cement job failed.

9.6.5 One other consideration: The casing seat may not be the weakest point in the next interval being drilled

The PIT will give guidelines about the maximum pressure which can be tolerated while drilling the next interval but breakdown pressure may be lower in some weaker sands – if wellbore pressure can enter a small crack. If a good thin drilled-solids-free filter cake is maintained, these incidences of lost circulation can be prevented.

9.6.5.1 Comment about "breaking down the formation"

Many feel that the formation integrity is totally compromised by creating this fracture during the pressure integrity test. The concept of "wellbore strengthening"' gives validation to the process. Some companies are now deliberately causing fractures and continuously packing them with solids. This increases the hoop stress around the wellbore and increases the break-down pressure. In other words, by inserting a propping agent in the fracture to keep it from closing, the breakdown stress is greater.

The near-wellbore stress distribution is different from the far-field stress distribution. This can be illustrated by looking at the stress distribution in a wall (Figures 9-12 and 9-13). In Figures 9-12 and 9-13, the length of the arrows indicates the magnitude of the stress. The ground supports the wall with a uniform stress matching the weight of the wall. The vertical stresses must be the same as the weight of the wall being supported.

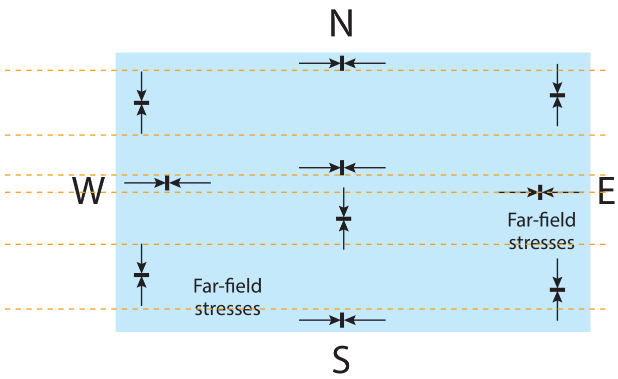


Figure 9-14: Horizontal stresses in the formation.

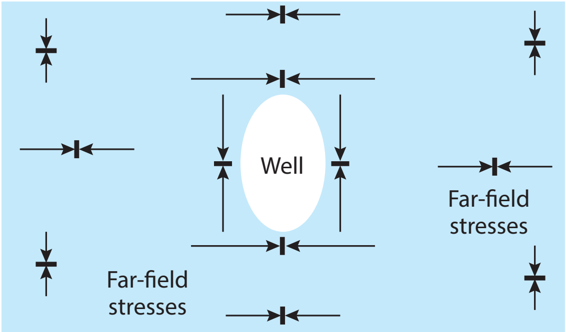


Figure 9-15: Stress adjacent to the well and the far-field stresses.

When holes are cut in the bottom part of the wall (Figure 9-13), only a small interval under each column is available for support. The vertical forces supporting the wall must still be the weight of the wall but they are limited to a much smaller area. The remaining columns of the wall must now support all of the weight of the wall. This means that the stress within each column is much larger than the stress was in that part of the wall before the holes were created.

This analogy helps explain the stresses around a wellbore. Before the well is drilled, the stresses are uniform and the forces resemble those shown in Figure 9-14. In this case the stresses that are oriented East and West are larger than the stresses oriented North and South.

This is a typical situation when drilling formations that had some type of tectonic activity normally required to form a reservoir. The stresses will be higher in one direction than the other. After the well Is drilled, this stress situation is disturbed. Just like the holes cut in the wall, the material supporting both the East/West and North/South forces have been removed. This means that the stresses next to the wellbore will increase higher than the original stresses in the area where the well is drilled.

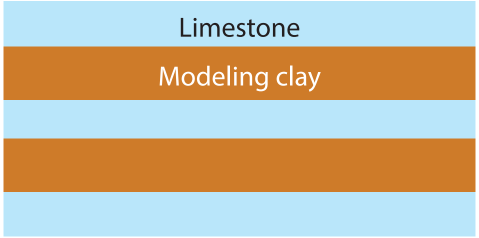


Figure 9-16: Layers of modeling clay between layers of limestone.

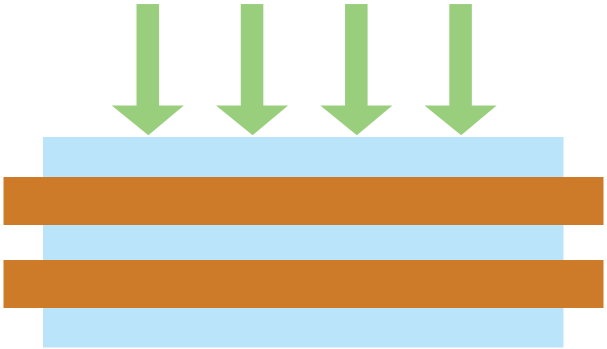


Figure 9-17: Stress applied to the top of stack will cause the modeling clay to deform. Horizontal stresses in the clay are much larger than the horizontal stresses in the limestone.

Removal of material from the formation increases the stresses adjacent to the wellbore. The far-field stresses remain the same. The stresses oriented East and West require a much larger force because the "weight of the wall" would need to be supported. The stresses oriented North and South must replace a smaller load but will still be larger than the original stresses that were in place before the well was drilled.

The large E/W stresses could be large enough to create a sufficient shear stress to cause the wellbore to collapse in that direction. This will leave an oval hole instead of a circular hole. Oval holes are common while drilling for production.

As an aside: Note that if pressure is applied to the inside of the well, a fracture can propagate more easily perpendicular to the small stress than perpendicular to the large stress. In this case the fracture would propagate in an East/West direction because the North/South forces are smaller. The PIT should measure the magnitude of the North/South stresses.

The stresses in the regions away from the wellbore still have their original distribution. However, these stresses are smaller than the ones next to the wellbore. This would indicate that the pressure required to propagate a fracture in this region would be smaller than the pressure for initiating a crack.

9.7: Comment about breakdown pressures in open hole

Imagine layers of modeling clay between layers of limestone (Figure 9-16). When weight is applied to the top of the stack, the modeling clay will tend to expand much more than the layers of limestone.

The horizontal stresses depend upon Poisson's Ratio. Poisson's Ratio in limestone Is around 0.2 to 0.3 and in the clay it is around 0.45. The horizontal stress can be calculated from the equation:

$$\sigma_h = \frac{v}{(1-v)} \sigma_v$$

Where:

σH is the horizontal stress
σv is the vertical stress
v is Poisson's Ratio

The horizontal stress in the modeling clay would be about 0.8 times the vertical stress. The horizontal stress in the limestone would be about 0.4 times the vertical stress (or much lower). When the wellbore ruptures, a fracture would be more easily propagated in the limestone than in the modeling clay. The stress holding the fracture closed in the modeling clay would be much higher. This is an extreme case. Usually, the difference in Poisson's Ratio is not that large in a well; however, this illustrates why the break-down pressure at the casing seat may be higher than the fracture pressure deeper in the hole.

References

1. AADE 2009NTCE -06-02 "Will a Leak-off Test Truly Damage the Wellbore?" Hong (Max) Wang, Halliburton, Frank Meng, ConocoPhillips, Mohamed Y. Soliman, Halliburton.

2. Zheng, et al., "Analysis of Borehole Breakouts," J. Geophysical Research Vol 94, No 86, Pg 7171 - 7182, June 10, 1989, "Borehole breakouts propagate into the rock until they reach a stable state".

Chapter 10
Load and Stability Analysis Of Casing Strings

TABLE OF CONTENTS

10.1 INTRODUCTION

The purpose of this chapter is to provide an understanding of pipe string stability concepts (lateral buckling) and how they are applied to prevent casing string failures due to the loss of stability. Stability failures in casing strings may result when they are exposed to changes in temperature, pressure and/or fluid density, relative to the conditions that existed when the string was set and installed. Loss of stability in a casing string allows lateral movement of the pipe to occur where it is not laterally supported; this can lead to failures due to casing wear from drill pipe rotation inside the casing while drilling below, from metal fatigue, or overstress from bending, or from jumped-out or backed-out collars at the connections. The axial force load that exists in a fixed casing string in a well is an integral part of its stability analysis and in the prevention of failures due to instability. This chapter will provide the methodology and equations needed to calculate both the stability loads and the axial loads for any casing string installed in a well under any set of operating parameters that the well environment presents.

Table 10-1 lists the nomenclature for the equations necessary to calculate stability and axial loads.

10.2 Casing stability

Arthur Lubinski, "A Study of Buckling of Rotary Drilling Strings," and other papers starting in 1950, Nils Muench, "Factors Affecting the Required Weight of Drill Collars in Fluid Filled Boreholes," Humble Oil proprietary report, Sept. 23, 1959, A. J. Chesney & J. Garcia "Load and Stability Analysis of Casing Strings," ASME, 1969, have proven that when pressure acts on the inside walls and not on the ends of a tube, this pressure can cause the tube to deflect. They also determined that conversely, when pressure acts on the outside walls of a tube and not the ends, the tube will tend to straighten. Casing cemented partway off bottom in a well or tubing latched to a downhole packer and landed at the surface are examples of strings where pressure only acts on the walls and are not impacted by pressures acting on the ends. Through experiments, mathematical analysis and observations, it was shown that certain cases of imbalance between internal and external pressures would cause the tubulars to buckle and bend (become unstable). From this work they also determined that if pressures caused deflections to occur it could be prevented by adjusting the axial load in the tube so that it would equal or exceed what Chesney & Garcia labeled as the "stability load." (Lubinski labeled this as the "fictitious load," and others combined this with the axial load and termed the total the "effective" load or force.)

The stability effect of the pressure acting on the walls of a casing string landed at the surface and cemented at a given depth tending to buckle the pipe is equal to $P_i \pi r_i^2$. The internal pressure, P_i, is the sum of any pressure applied at the top of the string and the head from the fluid to a given depth. The external pressure at the same given depth of the pipe tending to straighten the pipe is equal to $P_e \pi r_e^2$. The external pressure, P_e, is the sum of any applied pressure at the top outside the casing plus the pressure due to the head of the fluid density to the same given depth outside. The difference between $P_i \pi r_i^2$ and $P_e \pi r_e^2$ is called the "stability load," F_r, which is the minimum axial load required in a string at a given depth to prevent lateral movement under a given set of conditions as determined by the following equation.

$$F_r = P_i \pi r_i^2 - P_e \pi r_e^2 \qquad \textbf{Equation 10-1}$$

If F_r is negative this means that the internal buckling force is less than the external straightening force. If the difference is positive this means that the internal buckling force is greater than the external straightening force and the pipe is un-

Table 10-1: Nomenclature.

F_r = stability load, (effective load), lb	ρ_w = density of fluid inside casing when installed, lb/gal
F_a = axial load, lb	ρ_m = density of fluid in annulus when string installed, lb/gal
P_i = internal pressure, psi	ρ_c = density of cement, lb/gal
P_e = external pressure, psi	ρ_s = density of steel (490 lb/cu ft)
P_a = internal surface pressure when string was installed, psia	ρ_d = density of fluid in casing at time of interest, lb/gal
P_n = external surface pressure when string was installed, psia	ρ_a = density of fluid in annulus at time of interest , lb/gal
P_s = internal surface pressure at time of interest, psia	α = coefficient of thermal expansion for steel, (0.0000069 ft/ft/°F)
P_o = external surface pressure at time of interest, psia	ΔT = change in temperature of uncemented portion of string from installation to time of interest, °F
A = cross sectional area of casing, sq in.	W_p = load pulled ($+W_p$), or slacked off ($-W_p$), on casing at time of installation, lb
r_i = internal radius of casing, in.	μ = Poisson's ratio (0.3 for steel)
r_e = external radius of casing, in.	Conversion factors to oil field units (7.48 gal/cu ft, sq ft/144 sq in.)
X_t = total depth of casing, ft	X_i = any depth of interest, usually cement top, ft
X_c = depth of cement top, ft	E = modulus of elasticity for steel, 30 x 10^6 psi

stable under these pressure conditions. To prevent lateral movement the axial force in the pipe must then be equal or greater than the stability load. As long as the axial load in the pipe at the depth of interest exceeds the stability load required then the pipe will remain stable. If the stability load required at a given depth as determined by Equation 10-1 is 40,000 lb, then the axial load at the same depth must equal or exceed the stability load for the pipe to be stable. Sometimes the pipe may be in tension, but it may not exceed the stability load required to prevent buckling. In these cases one way to remedy the problem may be by adding axial load (tension) when the pipe is installed equal to or greater than the stability load, so that the pipe will be stable under the assumed conditions that will occur later.

10.2.1 What forces cause the pipe to buckle from internal pressure?

How can pipe buckle from internal pressure acting on the walls even if tension exists in the pipe? It is because any column of fluid inside the tube plus any added pressure applied to it at the top of the column acts on the walls of the tube and as a vertical downward load on the entire column made up of the tube and the fluid inside. Over any long column of casing some curvature exists because no column is perfectly straight without small deflections (Figure 10-1). These deflections have two effects on buckling: one is caused by the weight of the fluid column (with no rigidity of its own) acting down as an off-center bending moment across any slight bends in the tube. This is similar to what the case would be if a solid steel tube would be stood on end like a flag pole. In the case of a solid tube the internal solid part of the tube does offer added rigidity to the total tube while a liquid filled center does not. Even in the case of a solid tube (rod fixed at the bottom), however, eventually at some height the rod would bend and buckle under its own weight, unless an upward force was pulled from the top to counter the downward force and straighten the pole. The other effect is that these slight curvatures in the tube result in a greater surface area along the curved surface on the outside of the bend then on the inside of the bend inside the slightly curved tube (Figure 10-1).

By examining the curved sections on Figure 10-1 it is easily seen that the pressure acting on the walls inside the tube will result in a greater net bending force pushing the tube in the direction of the greater curved surface area along the outside of the bend causing it to deflect. The outside of the tube also has a greater surface area along the outside of the bend of the tube then on in the inside of the bend. The net result of any pressure acting on the outside walls of the tube, is that it will tend to push on the greater area on the outside of the bend of the curved tube wall in a direction that would try to straighten the tube. The difference between these lateral forces at any depth in the string will determine whether the pipe will tend to buckle or to be straightened. If the pressure inside and outside the tube are equal the net effect would be to straighten the tube because the outside surface area of a tube will always be greater than the inside surface area. The magnitude of the lateral forces at a given point in the casing installed in a well, however, cannot be determined precisely, because they will be dependent on the degree of curvature in the bends of the pipe and the length of the curve, which is unknown. The important thing, however, is that as long as the stability load for a given pressure condition is known at a given depth as per Equation 10-1, and the axial load in the pipe at that depth is equal or exceeds the stability load then the pipe will remain stable. Positive axial load in the tube at the point in question will always serve to attempt to straighten the tube and counter the buckling forces caused by both the weight of the fluid column and internal pressure.

To ensure that a string will remain stable during operations subsequent to initial installation, a thorough understanding of axial load and stability load changes that occur during those operations is required. If anticipated operating conditions exist for which string instability will result, tensile load adjustments in the string often can be made at the time of installation in order to prevent the buckling from occurring under the anticipated future instability conditions, (time of interest). If a mandrel type hanger is being used, (instead of a slip type), as in an offshore well, or when using a unitized head, adding tension when landing the casing after the cement sets cannot be achieved; in these cases it will be necessary to adjust the cement top to a depth where stability can be maintained.

10.3 Stability load analysis

Examination of the stability Equation 10-1 shows that internal pressure acting at the end of a closed end tube results in an axial load exactly equal to the stability load caused by the pressure acting on the walls even if the external pressure is zero. (Refer to Figure 10-2b) A casing string has been run in a well, cement has been pumped and the cement wiper plug has landed in the cementing collar, the cement is still fluid, and the pipe is not stuck. When a pipe string is vertically suspended, but not fixed at the lower end, the axial load at the lowermost point is exactly equal to the stability load regardless of the internal or external pressures. The force acting on the walls at the bottom of the string trying to buckle the string is $P_i \pi r_i^2$, but the axial load added to the string on bottom being caused by the internal hydrostatic pressure of the mud above acting on the cross sectional area of the cementing plug is also equal to the same force acting down. When the axial load is exactly equal to the stability load the string is exactly stable at its lowermost point. It will, as a rule, be more stable at upper points because axial loads

FIGURE 10-1

FORCES ACTING ON TUBES CAUSED BY DOWNWARD FORCE OF FLUID PRESSURE INSIDE TUBE AND PRESSURE ACTING ON THE WALLS.

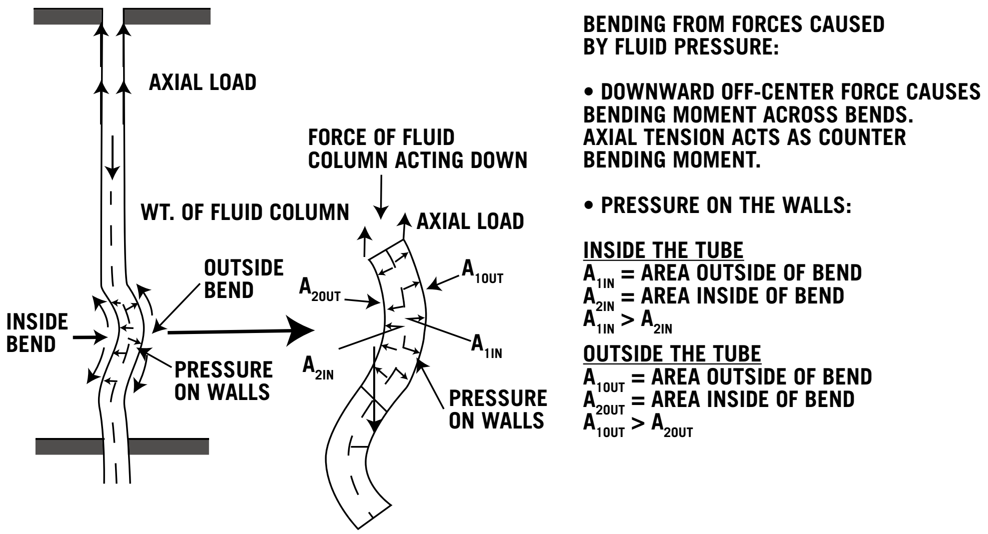
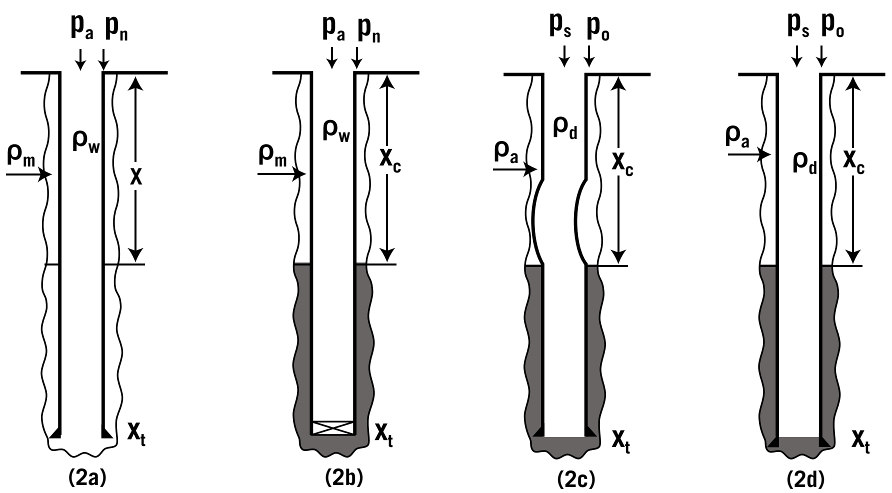


FIGURE 10-2 CONCEPTS OF PIPE STRING STABILITY



FREE HANGING STRING AT TIME OF INSTALLATION

CEMENTED STRING AT TIME OF INSTALLATION BEFORE & AFTER CEMENT SETS

CONDITIONS AFTER ENDS OF STRING ARE FIXED AT TIME OF INTEREST. STRING UNSTABLE, STABILITY LOAD EXCEEDS AXIAL LOAD

CONDITIONS AFTER ENDS OF STRING ARE FIXED AT TIME OF INTEREST. STRING STABLE, STABILITY LOAD LESS THAN AXIAL LOAD

Figures 10-1 (top) and 10-2: Forces acting along the axis and on the walls of a curved tube.

up the hole are higher due to string weight hanging below and exceed stability loads at these points.

Although stable at the time of installation, a string may become unstable after it becomes fixed in the hole because of pressure and temperature changes resulting from subsequent operations. Changes in both stability loads and axial loads will occur because of these changes, and it is possible for axial loads to become less than the stability loads, in which case stability of the string is lost. This is illustrated by Figure 10-2, which first shows in Figure 10-2a, a string of pipe suspended in a wellbore at the surface before the cementing operation begins. In Figure 10-2b cement has been pumped in the casing, the plug has bumped, the cement is still fluid, and the pipe is free. The string is stable, as discussed in the paragraph above. If the lower end of the casing is fixed when the cement sets so that pressure communication between the inside and outside of the casing is no longer possible, the string still remains stable at and above the cement top after it is landed, unless the fixing process results in an axial load reduction, in which the stability load would exceeds the axial load at the cement top, and the string becomes unstable. Assuming no axial load change when the lower end is fixed and the pipe is landed at the surface, the string remains stable.

The string can become unstable, as shown in Figure 10-2c, if operations cause internal pressures to increase, but external pressures remain the same as those when installed, and/or temperatures increase and insufficient axial loads exit to prevent it. Understanding the causes for instability and that additional axial load in the casing can prevent it, a simple approach to correct the problem, when possible, would be to pull up on the casing with the added tension needed to keep the pipe straight under the adverse conditions, as shown in Figure 10-2d. The question then becomes, how much tension is needed to keep the pipe straight? This question can be answered by doing both a stability analysis and an axial load analysis under a given set of operating conditions and comparing the two. As discussed above, loss of stability will first occur at the lowermost fixed point where the string is free to move laterally. (Placing the cement top higher up the hole can also result in increased axial load at the deepest free point in the casing, so that the pipe can remain stable under the anticipated operating parameters expected in the future.) It is, therefore, necessary when doing an analysis to consider only the lowest unsupported point, as all other points above in the string will be stable if it is stable.

10.4 Factors that influence stability and axial loads

The discussion that follows will apply to any casing string installed in a well that is fixed or partially cemented downhole and is then either hung above, as a liner inside an existing outer string, or landed at the wellhead and laterally unsupported between the two points. A protective casing string example has been selected for this discussion because they generally are exposed to greater changes in operating conditions than any other strings in a well and they are also exposed to the most potential wear while drilling a well. Stability is lost in a casing string when pressure changes result in stability loads that exceed axial loads. It, therefore, follows that loss of stability can be prevented by adjusting axial loads when a string is installed so future axial loads will always be greater than future stability loads.

Such adjustment, where possible, is often necessary to ensure stability of a protective casing string. (Where adjusting the load is not possible changing the depth at which the casing is cemented is normally the alternate solution which will be discussed below.) Increases in internal pressures and possible decreases in external pressures after installation cause stability loads to increase without comparable axial load increases. Increased temperatures due to fluid circulation from deeper drilling reduce axial loads in a string. Loss of stability can be prevented by cementing the entire string, but in most cases, this is not practical; and installations similar to that illustrated by Figure 10-2c result.

Operations subsequent to installation of a protective casing string frequently require the density of the fluid inside the string to be increased, and internal pressure at the critical depth increases accordingly. Internal pressure increases can also occur when testing the casing or casing shoe or if a well kicks and pressure increases in the casing while bringing the well under control. Such pressure increases will cause stability loads to increase. Additional stability load increases can also occur if reductions in external pressure occur at the critical depth, as might be the case if the mud left in the annulus should settle over time, and result in a lighter column of mud in the annulus at some depths above the cement top.

Prediction of surface pressures and fluid densities to be used in subsequent operations obviously requires considerable judgment and complete knowledge of operations for which the casing could be used. The important point is to determine, as accurately as possible, the internal and external pressures that will exist at the critical depth.

As previously discussed, string stability is a function of where and how well the string is cemented. Continued stability in the casing is largely a function of where the cement top occurs. Stability is enhanced as the depth to the top of the cement decreases, because the hydrostatic head of the fluid inside is less as the column is shortened and because the critical point is moved up the hole where higher axial loads always exist. The stability load at any future time after the casing is fixed at the surface and at a given cement top can be determined by substituting future pressure and density conditions at a given time of interest and for a given cement top in Equation 10-1 as follows: (The following equation includes necessary conversion factors, of 7.48 gal/cu ft, and sq ft/144 sq in. to allow substitutions in the equations using oilfield units.)

Substitute in Equation. 10-1:

$$F_r = P_i \pi r_i^2 - P_e \pi r_e^2$$
$$P_i = (P_s + \rho_d\,(7.48)\,X_i/144)\,\pi r_i^2$$
$$P_e = (P_o + \rho_a\,(7.48)\,X_i/144)\pi r_e^2$$

Where:

X_i = true vertical depth of interest, ft (usually cement top)

The equation simplifies to:

$$F_r = (P_s \pi r_i^2 + 0.163 \rho_d X_i r_i^2) - (P_o \pi r_e^2 + 0.163\ \rho_a X_i r_e^2)$$

Equation 10-2

Once the stability load for a given set of density and pressure conditions and a given cement top is determined, it must then be compared to the axial load that will exists in the casing at that depth under the same set of conditions. If the axial load exceeds the stability load then the string is stable for the parameters assumed. If the axial load is less than the stability load then axial load can be added to the casing when it is first installed or a higher cement top can be considered to move the critical point up the hole. The required axial load that must be added to the casing string at the time of installation for the cement top and pressure conditions assumed in the case above can be expressed by the following equation:

$$F_{add} = F_r - F_a$$ **Equation 10.3**

Where:

F_{add} = Additional load required for stability, lb
F_r = Stability load, lb
F_a = Axial load, lb

10.5 Axial load analysis

As previously defined, the stability load is the minimum axial load required in a string to prevent its lateral deflection under a set of conditions. Although axial loads will generally exceed stability loads when the string is installed, they may become less because subsequent operations cause changes in both stability loads and axial loads. If so, axial loads can be adjusted, when the string is installed so load deficiencies and loss of stability will not occur in the future. To make the proper adjustment, to meet or exceed the stability load requirements as described by the paragraphs 10.2, 10.3 and 10.4 under operating conditions at all future times, it is necessary to determine the axial load requirements at all of the same future times. The required adjustment to axial load will be the maximum load deficiency, if any, as determined by this analysis.

While axial load analysis is important to ensure that a string will remain stable under various operating conditions, it is also critical to make sure that the string is adequately designed to withstand maximum axial loads over the life of the well. Maximum axial loads do not, as a rule, occur at the time of installation or when the most adverse stability conditions occur. It is possible for the load capacity of a string to be exceeded because of future wellbore conditions, and even more so if axial loads are intentionally increased at the time of installation without increasing the load capacity of the string.

To better understand the loads that exist in a string and the changes that occur when operating conditions change, it is convenient to once again consider the protective casing string shown in Figure 10-2. When the string is installed, the cement is still fluid, and if the casing is not stuck, the axial load at any point "X_i" between the surface and the bottom of the string is simply the summation of all the loads acting below the point. These loads are the air weight of the steel below the point, plus the pressure inside the casing, from the hydrostatic pressure of the fluid and any pressures that might be applied at the surface, acting down on the cross-sectional area of the cement wiper plug, minus the pressure outside the casing on the annulus, at the bottom of the hole, acting up on the cross-sectional of the end of the pipe on bottom as given by Equation 10-4 below. As in the case of Equation 10-1, the 7.48 gal/cu ft and sq ft/144 sq in. constants used in this equation allow the use of oilfield units for mud weight and lengths. The equation for the load at any depth, X_i, at the time the casing is installed can then be expressed follows:

$$F_a = \rho_s(X_t - X_i)A/144 + P_a \pi r_i^2 + \rho_w (7.48)(X_t \pi r_i^2)/144$$
$$- P_n \pi r_e^2 - [\rho_m X_c + \rho_c(X_t - X_c)]\ (7.48)\ \pi r_e^2/144$$

Equation 10-4

If no change occurs in the temperature, pressures and fluid densities, after the cement sets, axial loads at all points remain as when installed. However, axial loads in the free portion of the string from the surface to the top of the cement do change when temperatures, pressures and fluid densities change after the ends of the string are fixed. The axial load changes that occur from pressure and fluid density differences are the result of hoop and radial stress effects caused by changes in pressure acting on the walls of the casing between the surface and the cement top relative to installation conditions. The axial load changes can be determined by using Hooke's law and the Lame' equation for thick wall cylinders. Substituting values for the expected pressure and density changes in the following Equation 10-5 then yields the axial load change that will result under expected conditions at the "Future time of interest."

$$\Delta F_{h+r} = -2\pi\mu\ \{(P_a - P_s)r_i^2 - (P_n - P_o)\ r_e^2$$
$$+ [(\rho_w - \rho_d)r_i^2 - (\rho_m - \rho_a)\ r_e^2]\ (7.48)\ X_c/288\}$$ **Equation 10-5**

Where:

ΔF_{h+r} = Change in axial load due to hoop and radial stress from density and pressure changes in uncemented part of casing at time of interest
P_a, P_n, ρ_w and ρ_m, represent the applied pressures and fluid densities at the time the string was installed
P_s, P_o, ρ_d and ρ_a, represent the pressures and densities at the time of interest
μ = Poisson's Ratio for steel (0.3)

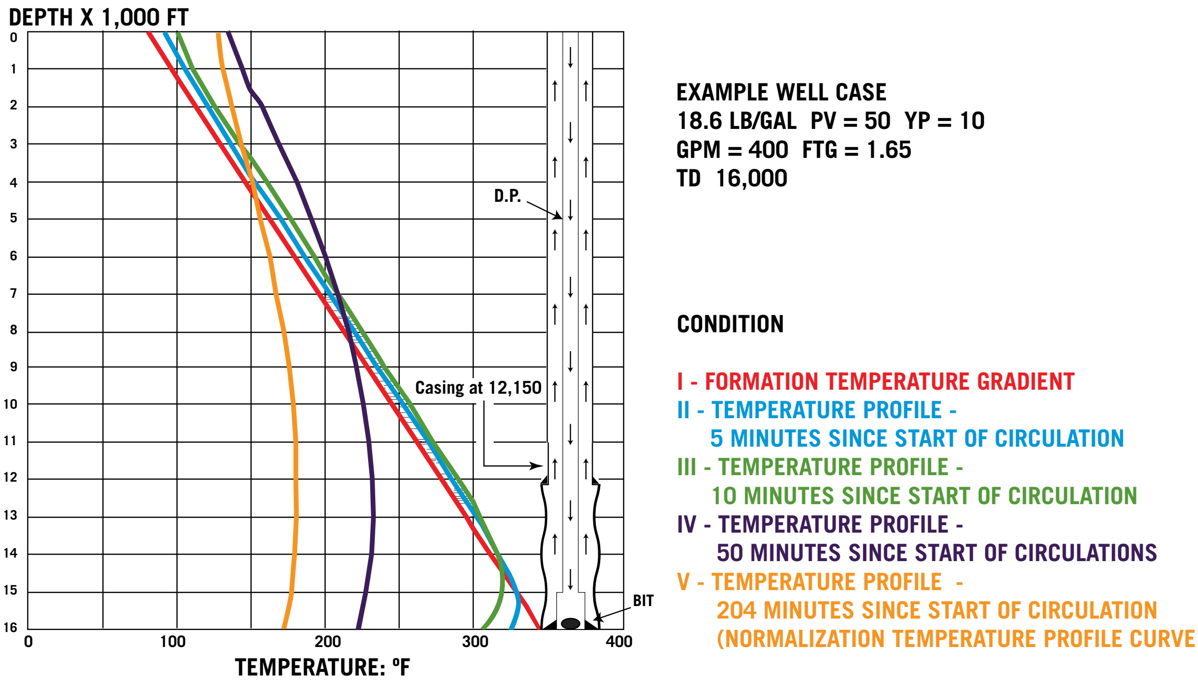


Figure 10-3: Circulation temperature profile example well case.

r_i =internal radius of casing, in.
r_e = external radius of casing, in.
X_c = depth of cement top, ft

These notations are also listed in the nomenclature following the introduction paragraph.

Axial load changes in the uncemented portion of the string also occur when the average temperature of the unsupported section at a future time differ from the average temperature when the casing was cemented and landed at the surface. Average temperatures in a protective casing string will normally still be warmer than geostatic but within a few degrees near the average of the static formation temperatures gradient, when the ends become fixed. This is assuming that the hole had been finished for several days before running pipe. First the hole was logged; then a clean-up and mud conditioning trip followed, and then the casing was run. After running the casing and circulating bottoms-up the cement job followed. Under this scenario the near wellbore temperatures would have been decreasing back to towards normal formation temperature gradient during these operations vs what they were when the well was drilling and circulating hot mud continually towards the top of the hole. Assuming that the temperature of the uncemented section of casing is at the normal static temperature when it becomes fixed is the most conservative assumption from a stability standpoint since it represents the coolest that the casing can be when it becomes fixed at both ends. (Computer programs are available in the industry to model any circulating or static temperature and timing scenario for conducting a cementing operation to help establish the temperature behavior of the well during a logging, casing and cementing operation. Temperatures after the casing is cemented in the hole will be a function of the operations that will be conducted in the future and should be determined as precisely as possible again with the use of the available computer simulation programs.) In the case of a protective string, the well will be drilled deeper and into hotter formations so the upper portion for the casing will be exposed to heating from the hotter circulating mud coming from bottom. The results from these analyses should then be used to determine what the net temperature changes in the unsupported section of the casing will be for the operations contemplated at the future "time of interest." Figure 10-3 is an example set of curves showing what a circulating temperature profile would look like over different circulating times when compared to a static temperature gradient. In this example a protective casing string was set at 12,150 ft and the circulating profile shows what the circulating curves would look like over time when drilling from a depth of 16,000 ft while circulating at 400 gal/min. The change in temperature in the unsupported section of casing will be the difference between the average temperature gradient when the casing became fixed by the cement and the average temperature profile expected in the future at various circulating times. Since the casing string is fixed at both ends so that it cannot lengthen, the attempted strain change from the thermal effects would instead result in a negative stress or load change in the string. The load change due to temperature change, ΔF_{temp}, can be calculated using the following equation which is a one dimensional version of Hooke's law:

$\Delta F_{temp} = -AE\alpha\Delta T$ **Equation 10-6**

Where:

- ΔF_{temp} = change in axial load due to temp. change, lb
- A = cross sectional area of csg, sq in.
- E = modulus of elasticity for steel, 30 x 10^6 psi
- α = coefficient of thermal expansion for steel, 6.9 x 10^{-6} ft/ft/°F
- $\Delta T = T_2 - T_1$ [Average temperature change between when the casing was installed (T_1) and the time of interest (T_2), °F]

Heating from time of installation to a future time of interest would result in a reduction in tensile axial load in the uncemented portion of the hole potentially putting the lower end of the casing in compression.

Finally, the last possible axial load change that needs to be included in the equation required to determine the axial load in a casing string under a future set of operating parameters, (time of interest) is any intentional mechanical adjustment of axial loads, if any were made, in the upper portion of the string (above the top of cement) before landing the string and fixing the upper end. If $+W_p$ represents addition of tensile load and $-W_p$ represents the reduction in axial load (slacking-off) then this load must be included in the final load equation to be complete. After taking the temperature and mechanical load changes into account the final axial load equation at the time of interest at any point "X_i" between the surface and the top of the cement is as follows:

Equation 10-7, F_a (axial load at time of interest at any depth X_i) = (F_a, axial load at time of cement setting, Equation 10-4) + (F_{h+r}, change in axial load in the unsupported section of casing caused by hoop and radial stress due to pressure and density changes inside or outside the casing at the time of interest, Equation 10-5) – (F_{temp}, change in load due to temperature changes in the unsupported section of casing at time of interest, Equation 10-6) +/ – (W_p, axial load added or slacked off on casing at the time it was installed).

In non-verbal terms,

$$F_a = \rho_s (X_t - X_i)A/144 + P_a \pi r_i^2 + \rho_w (7.48)\, X_t\, \pi r_i^2/144 - P_n \pi r_e^2 - [\rho_m X_c + \rho_c(X_t - X_c)]\,(7.48)\pi r_e^2/144 - 2\pi\mu\,\{(P_a - P_s)r_i^2 - (P_n - P_o)r_e^2 + [(\rho_w - \rho_d)\, r_i^2 - (\rho_m - \rho_a)\, r_e^2]\,(7.48)\, X_c/288\} - AE\alpha\Delta T +/- W_p$$ **Equation 10-7**

Equation 10-7 can be simplified by entering the density of steel for pipe as a constant = 490 lb/cu ft. In order to further simplify this equation the constants such as 7.48 gal/cu ft, and sq ft/144 sq in., and the factors such as π, µ,E,and α, can be divided or multiplied out as the equation indicates where convenient to yields the following simplification:

$$F_a = 3.40\,(X_t - X)\,A + P_a\,\pi r_i^2 + 0.163\,\rho_w\,X_t r_i^2 - 0.163\,r_e^2\,[\rho_m X_c + \rho_c\,(X_t - X_c)] - P_n \pi r_e^2 - 1.885\,\{(P_a - P_s)r_i^2 - (P_n - P_o)r_e^2 + [(\rho_w - \rho_d)\,r_i^2 - (\rho_m - \rho_a)\,r_e^2]\,X_c/38.5\} - 207A\Delta T +/- W_p$$ **Equation 10-8**

Equation 10-8 can be used to calculate the axial loads at any point "X_i" in the uncemented portion of the casing string between the surface and the cement top for any set of operating conditions.

10.6 Load adjustments for stability

As previously indicated, for any string to remain stable axial loads must equal or exceed stability loads at the critical point at all times; i.e., $F_a \geq F_r$.

If axial loads become less than stability loads at any time, adjustment of axial load is required after the cement has set for a string to remain stable. The required adjustment is:

$F_{add} = F_r - F_a$.

The critical point for a string, as shown on Figure 10-2c, is at the top of the cement. The minimum load adjustment necessary for the string to remain stable when the predicted operating conditions occur is the difference between the stability load, which may be calculated by the proper substitution in Equation 10-2, and the axial loads as given by Equation 10-8 at a future time of interest.

These equations should be solved using pressures, fluid densities, and temperatures predicted to result from each operation for which the string is to be used. The maximum load adjustment determined by taking the difference between the stability load and the axial load should then be made when the string is being installed. (If not possible, changing the cement top depth may be required to maintain stability at the time of interest.) Positive adjustment is necessary in most instances, but load reduction is possible after the lower end is fixed while still maintaining a stable string. This may be indicated in some cases where very high loads could exceed string capacity when future operations cause high axial loads to occur. It is important to note that typically the highest stability load requirements and the highest axial loads in a string do not occur at the same times. For this reason it is important to test for both cases when designing a casing string. This will be demonstrated later when using an example problem to help better understand how an analysis of a casing installation should be conducted.

The magnitude of the mechanical adjustment necessary generally becomes smaller as the depth to the cement top decreases. It is also obvious from the forgoing discussion that axial load changes in the uncemented portion of a fixed string are a function of internal and external pressure changes, temperature changes, and the length of the uncemented section of the string. If the increases in internal pressure and decreases in external pressure occur because of fluid density changes after the string is fixed, the increase in axial load becomes greater as the depth to the top of the cement increases. However, the same is true with respect to the stability loads when such pressure changes occur, except the increase in stability loads are greater than the axial load increases. The magnitude of the load adjustments necessary to ensure string stability, therefore, becomes greater as the depth to the top of cement increases.

To determine the proper load adjustment, it is necessary to calculate the changing effect that the predicted operating conditions will have on both the axial loads and stability loads as the depth to the cement top varies.

10.7 Example problem

To best illustrate how to use the preceding equations for field use, the technique is demonstrated with the following example. The procedure for determining the changing effect of density, pressure, and temperature of the operations on a cemented casing string is to assume at least two cement top depths and for each one to calculate the axial loads and the stability loads that will occur under the predicted future conditions. By using Equations 10-8 and 10-2, respectively, for the predicted operating conditions considered, an axial load and an additional load required for stability for each of the cement tops selected is, in effect, determined. The maximum load adjustments determined from this procedure for each cement top being considered can then be used to plot a graphical representation of the stability and load analysis results which can be very helpful both in understanding the concepts and in determining what corrective load adjustment may need to be made on a real time basis in the field. If for example lost returns were to occur while cementing so that the cement top were to wind up at a different depth than planned, the plotted curves can be used to quickly determine how much load will need to be added to the casing when the hanger is set to prevent loss of stability under the assumed future anticipated conditions. Building of the graphical representation for the data generated from the example detailed below will be displayed in Figure 10-4, Load and Stability Curves- Example well case, and described as the procedure unfolds.

Care must be exercised in choosing the most adverse conditions in doing both the stability analysis and the load analysis, if all operating conditions are not considered. During drilling operations the worst stability conditions above the top of cement will generally occur when the highest pressure and temperature occur at the same time in the uncemented part of the casing. This could happen if a kick were to occur while drilling the deepest part of a well with close to, or with the maximum density fluid expected, and the well was then to be shut in with pressure at the surface. (This would be the case if kill weight mud was used from the start of circulation down the drill pipe to bring the gas out of the well or if the well was already drilling with the maximum mud weight and the well was swabbed-in, when commencing tripping operations or when making a connection.)

After doing the analysis and determining the load adjustments required for the selected cement tops, under the worst stability conditions, the adjustments are assumed to be made for the purpose of calculating future axial loads under worst load conditions, as follows: After the well has been brought under control, and operating conditions again change, pressure, density, temperature and the added axial load, as determined from the stability analysis, are then used to determine the maximum axial load that will occur as a function of cement top depths by using Equation 10-8. The axial loads in the casing that need to be determined after the well is under control will be different and higher than in the kick scenario when the well was hot from circulating while drilling. The axial load analysis after the well is under control may have a higher mud weight as a result of having taken the kick and this will also be a factor impacting casing loads, particularly when tripping out of the hole, when the unsupported casing at the top will cool back towards the normal formation temperature gradient.

10.7.1 Example well case data

The example case will be for a well that will be drilled to a total depth of 16,000 ft. The casing program will be as follows:

Tubular program	Mud weights, lb/gal
Conductor: 20 in. as required	Preset
Surface casing: 13 ⅝ in. to 3,000 ft	9.5
Protective casing: 9 ⅝ in. to 12,150 ft	12.6
Protective Liner 7 ⅝ in. 11,800-14,500 ft	16.0
Production casing: 5 ½ in. x 5 in. to 16,000 ft	18.6
Production tubing: 2 ⅞ in. x 2 ⅜ in. to 16,000 ft	8.4

After setting conductor and surface casings, a 12 ¼-in. hole will be drilled to 12,500 ft, where the following 9 ⅝-in. protective casing string listed in Table 10-2 will be installed:

Table 10-2: Protective casing tubulars.

From, ft	To, ft	Length, ft	Weight, lb/ft	Grade	Thread
Surface	1,150	1,150	47	P-110	Buttress
1,150	1,850	700	43.5	N-80	Buttress
1,850	5,850	4,000	40	N-80	Buttress
5,850	8,050	2,200	40	N-80	LT&C
8,050	9,550	1,500	43.5	N-80	LT&C
9,550	10,950	1,400	47	N-80	LT&C
10,950	12,150	1,200	43.5	P-110	LT&C

This string is required to prevent loss of higher density drilling fluids, up to 16 lb/gal, into low pressure sands above 12,150 ft when drilling towards next liner setting at 14,500 ft, but it may also be required to:

- Allow testing and/or squeeze cementing of the casing seat to make sure returns will not be lost at this depth when drilling mud density is increased from 12.6 lb/gal to 16lb/gal;
- Control the well while circulating a gas kick from the well with 18.6 ppg mud near TD;
- Serve as a workover casing string for repair of production casing in the event it should develop a leak.
- Conditions at the time of installation are as follows (refer to Figure 10-2 as reference for nomenclature):

  $P_a = 0$ psi
  $P_n = 0$ psi
  $\rho_w = 12.6$ lb/gal
  $\rho_m = 12.6$ lb/gal
  $\rho_c = 13.8$ lb/gal
  $X_t = 12{,}150$ ft
  X_i = any depth of investigation

Worst conditions assumed for possible instability in the casing at a future time of investigation are as follows:

$P_s = 3{,}000$ psi, maximum casing pressure during a potential kick
$P_o = 0$ psi, no pressure expected on the annulus
ρ_d = 18.6 lb/gal, maximum expected mud weight inside casing
$\rho_a = 12.6$ lb/gal, no change in mud weight in annulus

The following cross-sectional area of the pipe and the radii used for this example are weighted average values for the string to simplify this example. This will only introduce a slight error given the magnitude of the assumptions of worst cases to consider. The proposed values to use are as follows:

$r_i = 4.39$ in.
$r_e = 4.8125$ in.
A = 12.212 sq in.

The selected cement tops for investigation in this example will be for X_c = 6,000 ft and 10,000 ft. The average circulating temperature increase for the two selected cement tops when circulating from the deepest depth in the well, compared to the average static formation gradient at the time the well was cemented, can be determined by using the data on Figure 10-3. (Note that the figure is specific to the example well and the comments below describing its use apply to this particular example. It is not a generic figure.) First the average static temperature for the uncemented section of the casing at the time of installation is determined. This is done by calculating the weighted average static temperature between the cement top and the surface for each of the selected cement tops. (See the formation temperature gradient curve, I, on Figure 10-3). Next the maximum average circulating temperature expected in the future in the uncemented section is determined. This is done by calculating the weighted average maximum temperature between the surface and the cement top using curve IV, for each selected cement tops. Note that the highest circulating temperature curve for the top of the casing occurs 60 min into the circulation cycle and that at 204 min into the cycle, the profile curve is actually cooler throughout the wellbore. This is because over time the circulating mud being pumped from the top has cooled the bottom of the hole, which reduces the temperature of the formation heat source that heats the mud as it is circulated back to the surface. The difference between the highest weighted average circulating temperature at 60 min, and the weighted average static temperature when the casing became fixed, then yields the highest expected temperature increase that will occur in the uncemented section in the worst case for each selected cement top being considered. This same procedure can be used for to determine the expected maximum temperature changes for as many cement top cases as desired. The following temperature increases, from static to circulating, were calculated from these curves for the selected cement tops:

$X_c = 6{,}000$ ft, $\Delta T = +38°F$
$X_c = 10{,}000$ ft, $\Delta T = +23°F$

10.7.2 Calculating the loads in the casing at time of installation

The first step in the analysis is to calculate the axial load and the stability load for the first cement top to be considered. Using the simplified version of Equation 10-8, first calculate the as-installed loads for the free hanging casing string for the case where the cement top X_c is at 6,000 ft. The buoyed load at 6,000 ft, before the cement sets, only requires substituting into the first part of Equation 10-8, using as-installed pressure and density conditions before landing the casing, with the cement still fluid. The equation past (-1.885) addresses hoop and radial effects, temperature changes, and added or slacked-off loads that will not occur until the future, after the casing is landed and well conditions change.

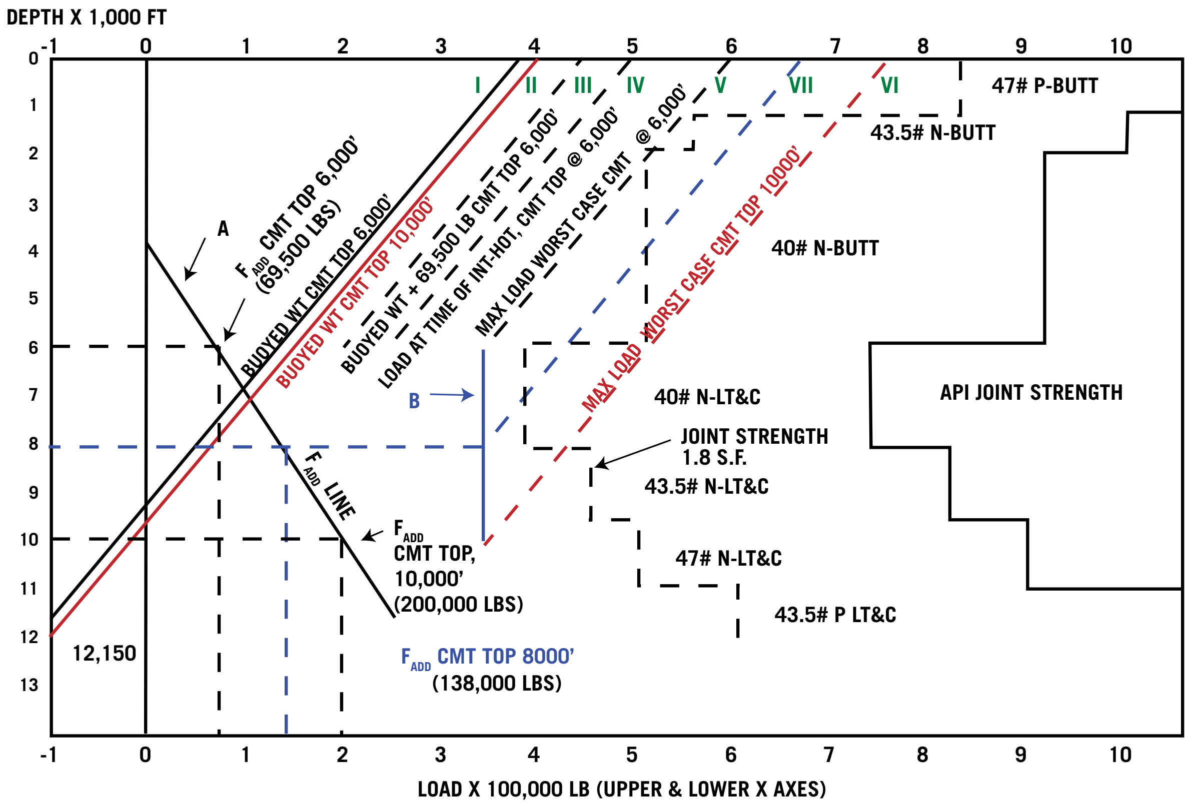


Figure 10-4: Load & stability curves for example well case, buoyed w.t. csg when installed axial load when landed, F_{add} at time of interest, worst-case loads.

These loads are "0" at the time of installation. Substitute X_i = 6,000 ft to calculate the buoyed weight at that depth as follows:

$$F_a = 3.40(X_t - X_i)A + P_a \pi r_i^2 + 0.163\rho_w X_t r_i^2 - 0.163 r_e^2[\rho_m X_c + \rho_c(X_t - X_c)] - P_n \pi r_e^2 - 1.885\{(P_a - P_s)r_i^2 - (P_n - P_o)r_e^2 + [(\rho_w - \rho_d)r^{i2} - (\rho_m - \rho_a)r_e^2]X_c/38.5\} - 207A\Delta T +/- W_p$$

$$F_a = 3.40(12{,}150 - 6{,}000)12.212 + 0(\pi r_i^2) + 0.163(12.6)(12{,}150)(4.39)^2 - 0.163(4.812)^2[12.6(6{,}000) + 13.8(12{,}150 - 6{,}000)] - 0(\pi r_e^2)$$

$$F_a = 255{,}352 \text{ lb} + 0 + 480{,}909 \text{ lb} - 605{,}791 \text{ lb} - 0 = 130{,}470 \text{ lb} \qquad \textbf{Equation 10-8}$$

This is the buoyed axial load at 6,000 ft.

The buoyed load at the surface can be determined by substituting "0" for the depth of interest, "X_i." This essentially is the buoyed weight at 6,000 ft plus the air weight of the pipe above to the surface.

F_a = 3.40(12,150 – 0)12.212 + 0 +480,909 lb – 605,791 lb – 0
= 379,807 lb, **buoyed weight at the surface**

As a last step, calculate the load at the end of the string. Since there is no pipe hanging below 12,150 ft, the axial load at the end of the string at this time is the sum of the pressure inside the pipe acting down on the wiper plug minus the pressure at the bottom of the hole acting up on the wiper plug and the cross-sectional area of the casing:

F_a = 0 + 0 + 480,909 lb – 605,791 lb
= –124,882 lb

This is the net force at the end of the string.

The weight of the string at this time can be plotted as curve I on Figure 10-4, which will be used to graphically display the data for the load and stability analysis for this example.

At this time, before the cement sets, the string is perfectly stable at all depths. The stability load F_r at the bottom of the casing can be calculated using Equation 10-2, where $X_i = X_t$ (12,150 ft) inside the casing. Outside the casing, X_i is also = X_t, but in the stability equation it must be expressed as $X_c + (X_t - X_c)$, (6,000 + (12,150 – 6,000)), because the fluid density in annulus is made up of a cement column and a mud column that add up to a total height of X_t.

$F_r = (P_s\pi r_i^2 + .163\rho_d X_t r_i^2) - (P_o\pi r_e^2 + 0.163\rho_a X_i r_e^2)$

Equation 10-2

Modify for dual density fluids in annulus:

$F_r = (P_s\pi r_i^2 + .163\rho_d X_t r_i^2) - [P_o\pi r_e^2 + 0.163 r_e^2(\rho_a X_c + \rho_c(X_t - X_c))]$

$F_r = (0 + 0.163\ (12.6)\ (12{,}150)\ (4.39)2) - [0 + 0.163\ (4.8125)\ 2(12.6(6{,}000\ ) + 13.8(12{,}150 - 6{,}000))]$

$F_r = (480{,}909 - 605{,}792)\ \text{lb} = -124{,}887\ \text{lb}$

Stability load at the bottom of the string.

The stability load, F_r, at this time is exactly equal to the axial load, F_a, at the end of the string at 12,150 ft, as just calculated above.

Next calculate the stability load at 6,000 ft at the same time as the pipe is being installed:

Substituting in Equation 10-2, Depth of interest is at cement top, X_i= 6,000 ft:

$F_r = (0 + 0.163(12.6)(6{,}000)(4.39)^2) - (0 + 0.163(4.8125)^2(12.6(6{,}000)\ )$

$F_r = 237{,}486\ \text{lb} - 285{,}397\ \text{lb}$

$F_r = -47{,}911\ \text{lb}$

Stability load at 6,000 ft when casing is being installed. (Cement not set.)

As calculated at the beginning of paragraph 10.7.2, the axial load F_a at 6,000 ft at time of installation is 130,470 lb, which exceeds F_r by 178,380 lb. The casing is stable at 6,000 ft at time of installation.

The same analysis done for the cement top at 6,000 ft can be repeated to determine the "as installed" weight of the string with a cement top at 10,000 ft to establish its initial buoyed weight. These calculations were done and the results are plotted as curve II, shown in red in Figure 10-4. The calculated buoyed weight values for the casing with the cement brought 10,000 ft at the respective depths indicated are as follows:

Axial load at the surface = 398,000 lb
Axial load at the cement top at 10,000 ft = –17,500 lb
Axial load at the end of the string = –106,800 lb

Note that the string is slightly heavier than in the 6,000-ft case because there is less cement placed in the annulus, which is heavier than the mud and this result in a lower buoyant force acting on the end of the casing.

As in the 6,000-ft case, an analysis to compare axial loads to stability loads for the 10,000-ft cement top case, when the string is first installed and is free hanging, will also show that the string is stable at all depths of investigation. This is always the case because the stability load at any depth will always be $P_i\pi r_i^2 - P_e\pi r_e^2$. Any internal pressure, P_i, will always induce a tensile axial load at the end of a closed-end casing string exactly equal to the stability load regardless of what the external pressure on the casing may be.

10.7.3 Calculating the axial and stability loads at future time of interest after the casing is fixed and well conditions change

Once the cement sets and the casing string is landed and drilling progresses below the casing, pressures, densities, and temperatures will change and alter both the axial and stability loads in the fixed string. If the casing was landed with added tension or by slacking off relative to the "as installed" buoyed weight, this will alter both the initial as landed and future axial loads in the casing by the amount of the change. To ensure that the casing will remain stable during all future operations it is necessary to check both the stability and axial loads in the unsupported casing at the critical depth during the "worst case" scenario. As discussed earlier in this chapter, this generally will occur when the casing is subjected to the highest combination of internal pressure and density, with no increase in pressure or density on the annulus, and when heating of the casing, due to circulating temperature from drilling, occurs.

The data for the worst anticipated case for this example was listed above in the given data at the beginning of this section. The case assumes that the well is drilling near TD when an influx of gas enters the well at the start of a trip. The well is shut-in and the kick is controlled with 18.6 lb/gal mud (ρ_d) in the well. During the killing procedure well pressure at the surface (P_s) reaches a maximum of 3,000 psi. The well was drilling while pumping 400 gal/min and the circulating temperature profile in the circulating system is presented in Figure 10-3.

The first step in the analysis process is to calculate the stability load and the axial load at the selected cement tops under the worst anticipated case. The difference between the stability load and the axial load will then establish whether the casing will be stable at the selected cement top, or if axial load can be added to the casing when it is landed so that it will remain stable under the expected conditions at the worst future time of interest. Repeating this process using a different cement top will then provide the data that is needed to help select the best option for where the cement top should be placed in order to avoid both the loss of stability and/or a potential casing failure from excessive axial loads under other possible well conditions in the future.

Calculate the stability load required for the worst case scenario at the time of interest if the cement top is placed at 6,000 ft.

Substitute in Equation 10-2, where $X_i = 6{,}000$ ft:

$$F_r = (P_s \pi r_i^2 + 0.163\rho_d X_i r_i^2) - (P_o \pi r_e^2 + .163\rho_a X_i r_e^2)$$

$$F_r = (3{,}000\pi(4.39)^2 + 0.163(18.6)(6{,}000)(4.39)^2) - (0 + 0.163(12.6)(6{,}000)(4.8125)^2)$$

$\mathbf{F_r = 246{,}812}$ **lb**

Stability load for 6,000-ft cement top at time of interest.

Next calculate the axial load for worst stability case scenario at time of interest, cement top at 6,000 ft, using Equation 10-8 and a $\Delta T = 38^0$F (as given in the example case for this section):

$$F_a = 3.40(X_t - X_i)A + P_a\pi r_i^2 + 0.163\rho_w X_t r_i^2 - 0.163 r_e^2[\rho_m X_c + \rho_c(X_t - X_c)] - P_n \pi r_e^2 - 1.885[(P_a - P_s)r_i^2 - (P_n - P_o)r_e^2 + ((\rho_w - \rho_d)r_i^2 - (\rho_m - \rho_a)r_e^2)X_c/38.5] - 207A\Delta T +/- W_p$$

$$F_a = 3.40(12{,}150 - 6{,}000)(12.212) + 0 + 0.163(12.6)(12{,}150)(4.39)^2 - 0.163(4.8125)^2[(12.6(6{,}000) + 13.8(12150-6000)] - 0 - 1.885[(0 - 3000)(4.39)^2 - 0 + ((12.6 - 18.6)(4.39^2) - (12.6 - 12.6)(4.8125^2))6000/38.5] - 207(12.212)(38) +/- 0$$

$$F_a = 255{,}352 \text{ lb} + 0 + 480{,}909 \text{ lb} - 605{,}791 \text{ lb} - 0 + 142{,}952 \text{ lb} - 96{,}059 \text{ lb} +/- 0$$

$\mathbf{F_a = 177{,}363}$ **lb**

Axial load at 6,000-ft cement top at time of interest.

Axial load at the surface = **177,363 lb + 3.40(6000)(12.212) = 426,488 lb**

The additional load required for stability, $F_{add} = F_r - F_a$ at the time of interest for cement top at 6,000 ft is:

$$F_{add} = 246{,}812 \text{ lb} - 177{,}363 \text{ lb}$$

$$F_{add} = 69{,}449 \text{ lb}$$

Additional load required is ≈ 69,500 lb tension.

This point can be plotted as shown on line A as the first point of the F_{add} line on Figure 10-4 at 6,000 ft on the vertical depth scale and 69,500 lb on the horizontal load scale. If this load was pulled on the casing after the cement set this would add 69,500 lb to the entire string from the surface to the cement top when it was landed. The loads at the cement top at the time of installation after pulling the 69,500 lb would be 130,470 lb (load at cement top at installation) + 69,500 lb = 200,000 lb. The load at the surface would be 379,800 lb (load at surface at installation time when setting the hanger) + 69,500 lb = 449,300 lb. The axial load in the casing with this added tension is represented by a parallel dashed curve III in Figure 10-4, shown to the right of the as-installed loads lines for the cement top at 6,000 ft and 10,000 ft.

If the worst stability scenario analyzed in the case above for the cement top at 6,000 ft were to occur and the 69,500 lb had been added to the casing when it was installed, the maximum loads in the casing above the cement top when the well is shut in with pressure and still hot from circulating and drilling would be summed as follows: The axial load F_a at the cement top for the conditions at the time of interest is 177,363 lb, but this was without added tension, as calculated above. The load at the surface at the same time, again without added tension, is 434,070 lb, as calculated above. If the 69,500 lb of tension was added to the casing when landed them the loads would be, 177,363 lb + 69,500 lb tension = 246,863 lb at the cement top and, 426,488 lb + 69,500 lb = 495,988 lb at the surface. This can be plotted as the dashed curve IV in Figure 10-4. If the well were to cool down to the formation temperature gradient (as was assumed to have been the case at the time the casing was installed) during the shut-in period or while circulating at a lower rate during the killing process, the negative axial load from heating the casing while circulating during drilling would be lost, and add as much as 96,059 lb of tension back to the string. This would cause the axial loads in the casing to increase to: 246,863 lb + 96,059 lb = 342,922 lb at the cement top and 495,988 lb + 96,059 lb = 592,047 lb at the surface. This would be the worst possible axial load case for the 6,000 ft cement top scenario and is plotted as dashed curve V in Figure 10-4. The API axial load capacity ratings data as well as the load capacities with 1.8 safety factor for the installed casing string in this example are plotted to the right of the load curves just described. (Selection of a safety factor will vary between operators and is normally based on historical experience with success in avoiding casing failures over time.) Note that the load at 1,850 ft is just slightly over the casing strength capacity with the 1.8 S.F. but over 400,000 lb short of the API rating for the worst load case assumed. This should be acceptable, but if not then the design engineer can always change out the section for stronger pipe.

Next a load and stability analysis for a cement top at 10,000 ft will be done for comparison purposes and to complete Figure 10-4. This figure will serve as a real-time tool that can be used in the field to help make an optimum decision on how to land the casing if the cement job should experience lost returns when pumping the job.

Calculate the stability load, F_r, required to for the worst case scenario conditions for a cement top at 10,000 ft.

Substitute in Equation 10-2 where X_i = 10,000 ft:

$$F_r = ((3{,}000)(\pi)(4.39)^2 + 0.163(18.6)(10{,}000)(4.39^2)) - (0 + 0.163(12.6)(10{,}000)(4.8125^2)$$

$$F_r = 765{,}926 - 475{,}663 = 290{,}260 \text{ lb}$$

Stability load, cement top at 10,000 ft at time of interest.

Next calculate the axial load, F_a, for the same case scenario at the time of interest, cement top = 10,000 ft by substituting into Equation 10-8. Given ΔT at time of interest for cement top at 10,000 ft = +23°F.

$$F_a = 3.4(12{,}150 - 10{,}000)(12.212) + 0 + 0.163(12.6)(12{,}150)(4.39^2) - 163(4.8125^2)[(12.6)(10{,}000) + (13.8)(12{,}150\text{-}10{,}000)] - 0 - 1.885[(0\text{ -}3{,}000)(4.39^2) - 0 + ((12.6\text{ -}18.6)(4.39^2) - (0)(4.8125^2))(10{,}000)/38.5] - 207(12.212)(23) +/- 0$$

$$F_a = 89{,}311 \text{ lb} + 0 + 480{,}909 \text{ lb} - 587{,}670 \text{ lb} - 0 + 165{,}598 \text{ lb} - 58{,}141 \text{ lb}$$

$\mathbf{F_a = 90{,}000}$ **lb**

Axial load at 10,000-ft cement top at the time of interest.

The axial load at the surface at the time of interest is the load at the cement top plus the air weight of the casing above the cement to the surface.

F_a at surface = 90,000 lb + 3.4 (12.212) (10,000) = 505,207 lb

The additional load required for stability, F_{add}, at the time of interest for cement top at 10,000 ft is:

$$F_{add} = F_r - F_a$$

$$F_{add} = (290{,}260 - 90{,}000) \text{ lb} = 200{,}000 \text{ lb}$$

Additional axial load required. This point may be plotted on Figure 10-4 at a depth of 10,000 ft to complete the lower portion of the F_{add} line A as shown.

If the 200,000 lb of tension were pulled on the casing string at the time of installation after the cement set it would add that amount of axial load to the casing from the top of the cement to the top of the string where the casing was landed. The load at the cement top after pulling the additional axial load would be the sum of the weight at 10,000 ft when installed plus the tension added:

–17,500 lb + 200,000 lb = 182,500 lb

The load at the surface would be the surface buoyed weight plus the added tension:

398,000 lb + 200,000 lb = 598,600 lb

To avoid unnecessary additional clutter to the graph on Figure 10-4, this curve is not be plotted, since it would fall almost on top of curve V.

If the worst stability scenario being assumed for this example were to occur with the cement top at 10,000 ft and the 200,000 lb of extra tension had been added to the casing when it was installed, the maximum loads on the casing above the cement top when the well is shut in after taking the kick, would be as follows: The axial load F_a at the cement top for the conditions at the time of interest without the added tension was 90,000 lb and the load at the surface was 505,208 lb as calculated above. If the tension had been added when the casing was installed, the casing loads at the time of interest would be:

90,000 lb + 200,000 lb = 290,000 lb at the cement top, and
505,208 lb + 200,000 lb = 705,200 lb at the surface

These loads would exist under the worst anticipated density and pressure conditions after taking the kick, but while the well is still hot. If the casing were to cool down by the 23°F that it heated to while drilling and return to the normal temperature gradient (as was assumed to have been the case at the time the casing was installed), an extra 58,140 lb of tension would be added to the casing loads. The maximum worst case loads in the casing would then be:

290,000 lb + 58,140 lb = 348,000 lb at the cement top, and
705,200 lb + 58,140 lb = 763,300 lb at the surface

This data is plotted as curve VI, shown in red, on Figure 10-4 and labeled as worst load case for cement top at 10,000 ft.

Note that for this worst case load scenario, with the cement top at 10,000 ft, the casing loads will exceed the rated tensile capacity of the casing with the 1.8 safety factor being applied for all but the very top section of casing and for the casing below 8,050 ft. At the weakest point (1,850 ft) the casing loads are still 220,000 lb less than the API ratings. Since the casing string is being used to drill through, to finish the bottom part of the well, using very heavy mud, and will also be exposed to high temperature variations and potential wear, it would be wise to try to keep the worst possible axial loads within the selected safety factor. Fortunately this can be done with very little cost by moving the cement top up to 6,000 ft and landing the string with 69,500 lb of extra tension. As indicated by the analysis curves, this ensures both a stable string in the worst case scenario while keeping the maximum worst case axial loads closer to the tensile rating of the design with the 1.8 safety factor. (Alternatively the design engineer could also redesign the string by running the 47-lb P-110 Buttress casing down to 5,080 ft and then using 43.5-lb N-80 Buttress below there to 8,050 ft.)

10.7.4 Using Figure 10-4 to ensure load and stability integrity in field applications

The example load and stability analysis developed several load curves which are plotted on Figure 10-4. These curves represent loads in the casing under different assumed conditions of pressure, density, temperature, and intentionally added axial tensile load when the casing was landed, as well as when changes in these parameters occur due to well operations. The sequence of axial load curves plotted in Figure 10-4 begin from when the string was first run in the hole, followed by curves representing subsequent loads when operational events caused changes in density, pressure and/or temperature conditions.

During this analysis process a comparison between stability load and axial load under a given set of well parameters at a future time of interest assuming different cement tops was also made. The difference between the stability load required and the existing axial load under the same conditions, at the selected cement tops, was then used to determine whether a load deficiency would exist at this future time, such that the string would be unstable for those conditions. This deficiency load difference (F_{add}) was then assumed to have been corrected by adding "the additional load required" to the casing when landed to make-up the difference so that a future buckling problem under the assumed worst case could be avoided. When doing the axial load and the stability load analysis for different cement top depths, the well conditions case (density/pressure/temperature gradient) at the time of installation are the same. Likewise, the assumed altered conditions that will exist later at the time of interest are also the same, for whichever cement top the analysis is being done. The casing size and the depth of the hole it is being run in is the same. The only difference in the analysis for each case is where the cement top is placed.

The effects that casing weight, applied pressure, density, and temperature have on the axial load and stability load of a fixed unsupported casing in a well are equal, directly proportional or inversely proportional to the depth of the cement top. (Temperature changes in the casing do not affect the calculation of the stability load at any depth, but do affect the axial load which can impact the ability to meet the stability load required to avoid loss of stability in a string.) The difference in the weighted average temperatures in the top uncemented portion of the string between when the casing is cemented vs later when the well is drilling and circulating from the deeper and hotter formations is inversely proportional to the depth of the cement top. Weighted average geothermal temperature for the uncemented section of casing can be calculated as follows:

1. First, divide the length of the uncemented section into 1,000-ft increments;
2. Next, read the average geothermal temperatures for each of the 1,000-ft section increments off the static temperature curve I from Figure 10-3;
3. Multiply the average temperature for each section by the length of each section (1,000 ft);
4. Add the products of the sections and then divide the sum by the total length of the uncemented section. The result will be the weighted average geothermal temperature for the uncemented section.

Repeat the above process for the circulating temperature curve that has the highest temperature departure when compared to the geothermal temperature curve above the top of cement, (curve IV). The result will be the highest weighted average circulating temperature for the uncemented section when circulating from the deepest part of the well. Subtract the section weighed average geothermal temperature from the highest section weighed average circulating temperature. The difference represents the highest temperature increase that can be expected in the uncemented section for the worst case. The average temperature difference in the unsupported casing above a deep cement top is very small while the average change in temperature for a shallow cement top is much higher, as can be easily seen on Figure 10-3. For deep cement tops the temperature in the lower part of the casing is actually cooled relative to geothermal gradient while circulating the well. Plotting ΔT, the difference between average static geothermal temperature, (assumed to be the initial casing temperature in this example) and average circulating temperature for the uncemented casing between the surface and different cement tops vs cement top depth will be very close to being a straight line for cement top depths above about 70% of the casing depth.

The effect of pressure at the cement top due to fluid density increases proportionally with depth. The average pressure, over the uncemented portion of the casing due to hydrostatic head also increases proportionally with cement top depth. The weight of the casing below a given cement top depth is inversely proportional to depth because the amount of casing weight below is less as the cement top is placed deeper. Applied pressure at the surface is a fixed value at any depth. When pressure is applied at the surface it is exerted equally from the top to the deepest point. What this means is that when the difference between the stability load and the axial loads ($F_r - F_a = F_{add}$) for different cement tops is plotted on a linear graph of cement top depth vs additional load required to avoid buckling of the casing at the future time of interest, it will be very close to a straight line for cement top depths above 70% of the casing total depth. Line A in Figure 10-4 (F_{add} line) drawn between the point for the additional load required for the cement top at 10,000 ft, which is 200,000 lb, and the point for the additional load required for the cement top at 6,000 ft, which is 69,500 lb, and extended in both directions, can be used to determine the added load required for any cement top for the well case example presented in this chapter. The point where the extended F_{add} line crosses the vertical depth axis line indicates that for a cement top at 4,000 ft no additional load is required for stability for the given operational parameters case in this example.

Worst case axial loads conditions in the installed casing string at a future time of interest for different cement top depths were also calculated above. The worst load case assumed a kick scenario with maximum density fluid in the casing and 3,000 psi at the surface, after the casing string cools to normal temperature gradient in a shut-in condition. The analysis was done for a cement top at 6,000 ft and for one at 10,000 ft. The results were plotted as parallel curves V and VI respectively on Figure 10-4. Once the casing becomes fixed at the cement top and at the surface the axial load at the surface will always be equal to the axial load at the cement top plus the air weight of the steel casing to the surface. Plotting these axial load values vs depth for the casing will produce a curve with a slope equal to a fixed length of casing vs weight for the pipe (1,000 ft/41,500 lb) above the axial load calculated at the cement top. This slope is the same for any cement top under the assumed well conditions. After the casing is fixed and well conditions cause a change in axial load, the change will be reflected over the entire length of the string. If heating the string causes an axial load change of -30,000 lb, the reduction in load will occur from the surface to the cement top equally in either the case for the cement top at 6,000 ft or 10,000 ft. This would simply shift the load curve 30,000 lb to the left of where it was before, and still parallel to the old curve. What this means is that once the maximum load curve for the worst case scenario for the cement top at 6,000 ft and for 10,000 ft are established, curves V and VI respectively, they can be used to determine what the maximum worst case loads would be for any other cement top case under the same well conditions scenario including the addition of the corresponding, F_{add} (additional load required for stability). The graphical procedure to determine the worst load for any cement top under the conditions in this example can be accomplished by first connecting the worst case axial load point at the base of the 6,000-ft cement top (curve V) and the point at the base of the 10,000-ft cement top (curve VI) on Figure 10-4 together, forming line B shown in blue.

An example for a case where the cement top ends up being at a different depth than originally planned will help show how this tool can be used in a field real time case. Assume that a cement job called for the top of cement to be at 6,000 ft. When the cement job was being pumped lost returns occurred during displacement of the wiper plug and the cement winds up being at 8,000 ft instead. How much tension needs to be added to the unsupported string when landing it to ensure casing stability under the assumed worst case scenario for the well?

Go to Figure 10-4. Enter the vertical depth scale at 8,000 ft and draw a horizontal line to intersect the F_{add} line at 138,000 lb. This is the additional load that needs to be pulled on the casing when landed if the cement top winds up at 8,000 ft to maintain stability in the string, under the worst stability conditions assumed at the future time of interest. Next continue the horizontal line past the F_{add} line until it intersects the blue line B, connecting the maximum load points at the base of the cement tops max load curves for 6,000 ft and 10,000 ft. From the intersection of the horizontal 8,000 ft line and the Blue load line, draw a line parallel to lines V and VI up toward the horizontal load scale at the top of the graph as shown. Label this curve VII. This curve represents the max worst case load for a cement top at 8,000 ft under the same conditions at the future time of interest as for the cases for the cement top at 6,000 ft and 10,000 ft. The maximum axial load represented by this curve is for the worst case scenario after the casing has cooled to a geothermal gradient and with the addition of the 138000 lb of added tension when the string was landed to meet the added load requirement to remain stable. Note that the maximum loads expected are only slightly higher than the rated joint strength capacity of the string with a 1.8 safety factor. This solution can also be determined by using Equations 10-2 and 10-8 as in the example cases used above. The change in temperature for the 8,000 ft cement top case can be estimated using Figure 10-3. The process for determining the difference between the weighted average static geothermal temperature when the casing was installed and weighted average circulating temperature at a future time of interest was described earlier in section 10.7.4 above. The analysis should yield a ΔT of about 32 °F.

10.8 Special notes

The assumptions used in the analysis of a protective casing string in the example case in this chapter were based on use of the string in protective service while drilling the well. The assumption that the casing temperature was at geostatic when the casing became fixed was intentionally conservative for stability design purposes. This is so that heating due to drilling deep in the well would result in the greatest calculated ΔT for the unsupported section at the top of the well at a future the time of interest. If however, the casing was actually warmer than geostatic when it was fixed, future cooling scenarios would result in a higher tension load than calculated using the assumption that the casing had already cooled to geostatic when it was landed. Is this a problem? While this can possibly be a problem in an extreme case in a different well under a different scenario, it is inconsequential in the example case used here.

Example: Assume that the uncemented portion of the casing is at geostatic temperature when 69,500 lb tension was pulled on it at the time it was landed for the case with the cement top at 6,000 ft. If the casing was actually warmer than geostatic when it became fixed, it will still continue to cool further until it reaches geostatic at some point in time. If for example the casing were to cool an extra 6°F to reach geostatic conditions after it became fixed, it would add more axial load to the uncemented section over what was pulled. The extra tension due to cooling after landing the casing would be:

$F_{temp} = 207\ A\Delta T$ or $F_{temp} = 207(12.212)(6) = +15{,}000$ lb

This is an added tension of 2,500 lb/degree of cooling. (The 6°F warmer than geostatic number used above is the estimate of what the temperature would be in this example case as obtained by running the Wellcat temperature prediction program, which is one of several programs available in the industry. As previously indicated in this example, the geostatic temperature estimate was used instead to be more conservative from a stability standpoint.

In the worst case load scenario for the example well for the cement top at 6,000 ft (curve V Figure 10-4), the axial load on the casing with maximum anticipated surface pressure and mud density in the casing, and, after the casing has cooled to the assumed geostatic condition will breach the design curve at 1,850 ft. This is where the axial load curve V crosses the axial load capacity curve for the string with a safety factor of 1.8. When axial load curve V is compared to the API rating at the same depth, however, it is 400,000 lb less than the casing's true capacity. The correction to adjust for the extra 6° of cooling due to the possible errant assumption that the casing was at geostatic temperature would shift the axial load curve 15,000 lb to the right and still far short of the API rated casing capacity. Conclusion, this is not a problem.

To complete a more comprehensive analysis that also considers future operations after the well is completed with additional strings installed will require utilizing thermal predicting computer programs. Planned or unplanned future operations such as well stimulation or bull-heading to kill the well can also be analyzed to help get a more accurate picture of all of the installed string's potential axial load changes in the future. If, for example, a large stimulation treatment job is planned after the well goes into production, it is possible to determine what the maximum cooling will be in all of the installed strings. This information can then be used to compare with the installed conditions when the strings became fixed. Using this knowledge, Equation 10-8 can then be used to calculate the axial loads under the future time operating parameters.

The procedures and equations used in this chapter to analyze the load and stability conditions, and actions required to ensure string integrity during the life of the well, can be utilized for any string that may be installed during well construction or later during a workover. This process can also be used to help analyze the effect of temperature changes for a tieback or long string installations where longer term cooling of the ground surrounding the wellbore, and eventually the well, can impact the axial loads in the upper part of these strings. Knowledge of the installation conditions and all future possible operations is critical for proper safe handling of tubular goods.

If the casing string to be analyzed is tapered (multiple outside diameters), the weighted average casing area and radii should not be used to do the analysis. The analysis method should be applied for each section separately and then account for the axial load changes that occurs at the crossover area differences where the sizes change.

The procedure for adding tension to a casing string when it is being landed after cementing should be as follows:

1. After the cement is pumped and the plug has landed, read the buoyed weight of the casing. Compare it to the analysis estimate to make sure that the weight indicator is working correctly. (Subtract the weight of the block and other tools above the casing from the total.);

2. Mark the casing relative to the rotary table and either hang the casing on slips or hold the weight on the elevators;

3. Wait on cement as indicated from cement tests. As long as the string remains free no weight change should occur as the casing is cooling. Cooling will cause the free casing to strain (length change-shorten) but as long as the casing is free the weight should remain constant;

4. When the casing becomes "fixed"/or stuck by the cement, further cooling will cause the weight to increase relative to the initial free buoyed weight. At this point the mark on the casing should still be unchanged relative to the rotary table;

5. After waiting on cement as indicated by the cement company tests, check to make sure that the casing mark relative to the rotary table is unchanged. If it is different, bring the mark to the original spot. Record the weight of the string. If the weight of the string has risen by 20,000 lb, for example, this is due to the attempted strain change due to cooling after the casing was fixed downhole. If the intent was to land the casing with 60,000 lb (example) then all that needs to be added is 40,000 lb more tension to get to the right number. This is because the cooling that occurred after the casing was fixed has already added some of the desired weight;

6. The slips can now be installed while setting the casing weight at the hanger. Proceed with BOP lift and cut-off operations.

10.9 Closure

Sometimes people have difficulty visualizing or believing that a fixed tube held in tension with pressure acting only on the inside walls and not on the end can buckle. In the early discussion on this topic we presented a visual and mathematical approach to help better understand why and how this can happen. One other way that I have used in the past to help people understand the concept has been to use the analogy of a long balloon, like the ones used to make animal figures at a birthday party for kids, to help visualize how this happens. If someone takes one of these balloons and glues the closed end to the floor, and then stretches the blow-in end up to the ceiling in a room, you have an unsupported tube in tension. If you then attempt to fill the balloon from the top with water, gravity will act on the water and the balloon will buckle starting at the bottom end. This will cause the balloon to fall sideways before the water level ever reaches the top end. The diameter of the balloon towards the bottom will have expanded some amount. The increase in diameter near the bottom and buckling itself will cause an increase in axial tension in the balloon but it will not be enough to prevent the buckling from occurring. Why? The water and rubber column combination do not have enough rigidity (resistance to bending) to prevent buckling and the tension in the balloon is not enough to counter the downward weight (force, $P_i \pi r_i^2$) pushing down on the column at any given point.

If you think that using a balloon is not a fair comparison, then let's assume we have a thick rubber hose that is 100 ft long and does have some rigidity, and do the same thing as with the balloon but use mud to fill the inside. The same thing would happen as in the case of the balloon. These cases are the same as for a steel tube in a well fixed at the top of cement downhole and landed at the casing hanger at the top of the well. The composite column of steel and mud inside is very long and the fluid inside near the cement top of the cement exerts a very high downward force trying to force the column off center countered only by whatever tension exists in the pipe pulling up on the tube in the opposite direction. The rigidity in the pipe for such a long column with no rigidity at all being contributed by the fluid cannot prevent bending from occurring. This identical case is what occurs to a riser being used in a deep-water well when the mud density is increased to drill deeper. Every time the density is increased inside the riser, with only saltwater outside, it becomes necessary to pull additional tension from the rig to counter the downward force applied by the heavier mud inside and the pressure acting on the walls in order to prevent it from buckling. This can be proven mathematically using Euler's column formula to determine the "critical load." The critical load is the load at which a column will begin to deflect when it is subjected to a downward load. Critical load approaches "zero" for very long columns like casing strings which would buckle under their own weight, even when empty, unless added tension at least equal to the weight of the casing and fluid inside is pulled at the top when landed.

Chapter 11
Rig Site Well Control Training

TABLE OF CONTENTS

11.1 INTRODUCTION

The industry has many excellent programs in place to help train rig supervisors, rig managers, and drillers at all levels to identify, mitigate, and handle well control problems on drill wells. These programs go to great lengths to teach both theory and practice of well control. Training programs also include many hands-on drills on simulators and certification procedures through testing to make sure that those in charge of operations on the rig site are well versed in all aspects of prevention, identification, and proper handling of well control events, should they threaten the safety of a drilling operation. Since it is not always possible for the rig management personnel to be present at the specific rig location where the problem may first manifest itself, it is very important for the rig crews to also have the basic knowledge necessary to take action without first looking for the supervisor for instructions. To this end, rig supervisors, contractor rig managers and toolpushers must assume the responsibility to ensure that their rig crews have sufficient knowledge to identify the early signs of a potential impending well control event and to take the necessary steps required to shut the well in safely and properly. Regulations and contractual agreements establish the extent of training requirements and assigned responsibilities for all rig personnel.

Rig supervisors generally use well pre-startup meetings to discuss well control theory, practices and procedures with the crews. These sessions will include teachings and discussion on causes for kicks, early recognitions signs, and proper well control procedures that should be followed. Checklists such as trip books use, tripping procedures, and step-by-step sequences for securing a well when a kick is suspected are also covered in these sessions. "Pit drill" procedures to simulate a pit level gain and alarm (lifting the mud tank float) are also discussed and later practiced to ensure that the correct sequence for shutting in the well can be executed by all the crews in a safe and timely manner. The supervisor will generally report on morning reports about crew proficiency during the "pit drill". Unsatisfactory results will lead to a repetition until the drill is done to the supervisors' satisfaction.

Later, as the well progresses, operators will also have the crews perform a slow rate ("kill rate") circulation test through the bit with the drill string in the hole before drilling out of all installed and cemented casing strings. As the well gets deeper and/or as mud weight changes, this test will be repeated to establish new slow rate circulation pressure reference points. This slow "kill rate" procedure is an open well circulating test to determine the system circulating pressure when pumping at a rate that would be used to circulate out a kick if one were to occur in the section being drilled. The upper limit of the slow, "kill rate", is normally about half of what the circulating rate will be when drilling the section. Crews are taught to circulate a kick out with a drillpipe pressure slightly higher than the sum of the slow rate circulating pressure plus the drillpipe shut-in pressure. This procedure, known as the "Driller's Method" of well control, will result in maintaining the bottomhole pressure constant and above formation pressure throughout the process of removing the gas from the well. Circulating out a kick using the Driller's Method procedure will prevent any further entry of formation fluids into the wellbore while removing the gas that initially entered the hole. They are also taught that the drillpipe pressure is controlled by adjusting the choke on the casing side of the well and that a second circulation with heavier mud will be required to kill the well and replace the imposed pressure induced by the choke on the well.

Another good practice that can be discussed with the crews and implemented before drilling out of a cemented casing string involves pumping through the well control equipment system to check for leaks and/or possible plugging in the lines. This test is done by closing the annular BOPs and pumping down the drillpipe and through the bit, back up the annulus and through an opened hydraulic control valve (HCV), choke, and gas separator. The tests and drills described above and the reasons for doing them can be discussed and practiced with the crews so that they will understand how the information is used in controlling a possible kick and how important their knowledge and involvement is to a safe and efficient operation.

Pre-tour meetings with all the crews as the well progresses reinforce past learnings and drills, but also serve to discuss risks associated with the specific hole section being drilled at the time. Procedures for tripping and any hole-related issues are discussed with the crews with special emphasis on recognizing early signs of potential problems.

The practices and procedures discussed above are excellent initiatives to enhance crew knowledge and proficiency. Crew confidence and team building are two other benefits that result from crew training that increases their capability to recognize, react to and properly handle a kick should one occur on their rig. Having said this, however, nothing can substitute for the experience that is gained by having a crew actually handle a real gas kick situation on their rig successfully. Can this be achieved safely on a rig without taking an actual formation influx in a well?

The following discussion presents a procedure that has been used successfully in the past to conduct a kick simulation drill, for crew training purposes, using nitrogen gas in a cased well under controlled conditions.

11.2 Drill site well kick simulation procedure

The kick simulation procedure uses nitrogen gas to simulate a gas influx (kick) into the annulus between the drillpipe and casing at the bottom of the well just prior to drilling out of a deep-set casing string in an actual real drill well. The simulated kick is induced by pumping a predetermined volume of nitrogen into the top of the drill string, which is then displaced down the drillpipe and out the bit to the annulus between the drill collars and casing, causing the well to flow. The crew recognizes the problem and goes through the well shut-in sequence that they have previously practiced during a "pit drill". Readings of pressures and volume are taken and the kick is circulated out through the choke and mud separator until the gas has been removed from the well. Every aspect of the simulation is identical to a real kick, except that the gas is noncombustible and the well is not affected in any way since the kick is contained within the closed casing with no exposed formations.

Special note: For safety reasons this procedure should only be attempted in casing strings set deeper than 8,000-10,000 ft, because gas introduced to the well at shallow depths with light fluids can rise to the surface very quickly. This will present safety issues if the expanding nitrogen bubble blows through the rotary and on to the rig floor before the well can be shut in.

If a desire to simulate a shallow gas kick exists, an alternate procedure that can be safely employed is as follows:

1. Run the drill-out string to the surface casing shoe;
2. Lock the rotary bushings;
3. Close the BOPs, and open the HCV and the choke;
4. Open all the lines coming out from the separator;
5. Circulate the well through the system to make sure everything is open;
6. Pump a small amount of nitrogen into the top of the drill string and then circulate the gas down the drill string and up and out the annulus. (See the procedure below for rigging up and displacing the nitrogen through the system.)

The gas will reach the surface very quickly and make an impressive showing when it works its way through and out of the gas separator. This demonstration will serve to impress on the crews the importance of early identification of the beginning of an influx and staying away from the rotary area when shutting in a well. These types of simulations will also serve to determine the performance and location of the gas separator and fluid and gas lines leading to and away from the separator.

The procedure for conducting the controlled deep kick simulation on a rig is as follows (Refer to Figure 11-1).

1. After installing a deep casing string (not surface casing) in a well, the drill string is run to bottom in preparation for drilling out. The drill string should have a ported float installed a short distance above the bit to allow restricted, but open, pressure communication from the bottom of the well up the inside of the drillpipe to the surface. The kick simulation exercise can be done prior to drilling out from casing cemented above the pay zone or prior to drilling below intermediate casing in a high pressure well. (Refer to Figure 11-1a.) To begin the exercise, position the top tool joint on the drill string just above the rotary table with the bit within less than 30 ft of bottom. Install a drillpipe safety valve on top of the tool joint. Next, make up the nitrogen injection control head-on to the top of the safety valve as shown. The control head will have a safety valve above it and two valves on the side entry where the nitrogen source line will be hooked-up. If necessary, install a cross-over sub atop the safety valve above the control head to match the threads on the Kelly saver sub or the top drive lower connector. Make up either the kelly or the top drive onto the top of the crossover sub. Test all lines and connections. With the side entry valves closed, circulate the well at least one full circulation of the hole volume at normal drilling rate with the annulus open to condition the mud. Next, reduce the circulating rate to slow "kick rate" to establish the system circulating pressure at the well control rate that will be used for the simulation exercise. (The kick circulating rate should be about half of the circulating rate used when drilling and no more that 2-3 bbl/min.) Record the "kick rate" circulating pressure.

2. Register the level of the mud pits before starting the procedure required to introduce the nitrogen into the system. In order to reduce mixing of the nitrogen with the drilling mud and to prevent the gas from rising due to buoyancy while being displaced down the drillpipe, lead and tail spacers should be used ahead and behind the gas when it is placed in the drillpipe. The spacer should be formulated from the existing drilling mud system on the rig and will be used for both the lead and tail. Volume and recipe for the spacer pills will be discussed later in an example case to follow. The spacer fluid should be premixed and held in separate mix tank that can be piped to the circulating pumps. Pump half of the spacer fluid (lead) into the top of the drillpipe and register the new pit level.

3. Close the safety valve above the control head and the lower kelly valve. Bleed any pressure, but not the fluid in the surface circulating system, from the pumps to the top of the control head. The pressure

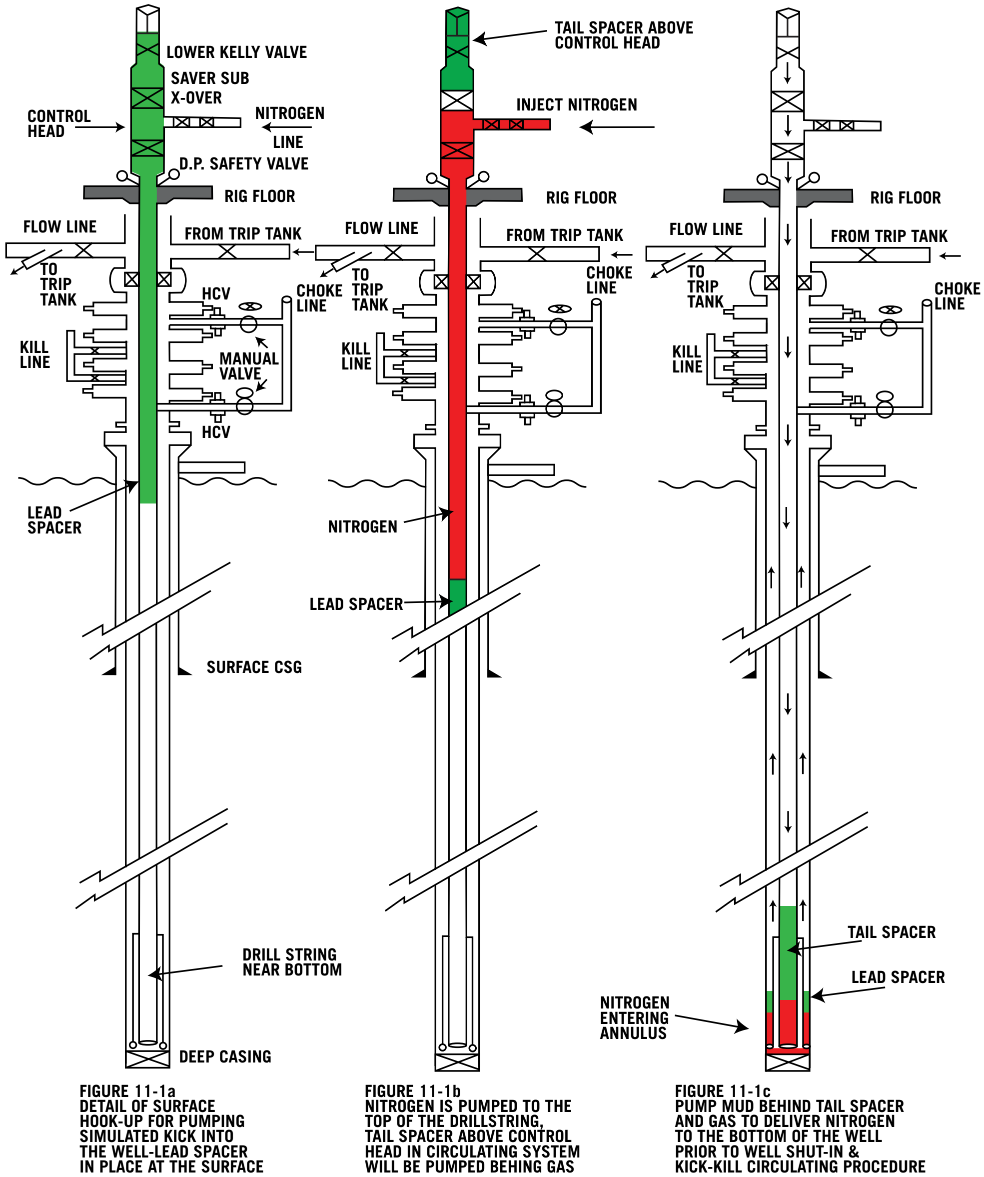


Figure 11-1: Sequence & surface hook-up for injecting & displacing nitrogen to the bottom of a casing string to simulate a kick influx in a deep well.

at the top of the drillpipe should be zero since the density of the spacer is the same as the drilling mud. The kelly and pumping system should still be full of spacer fluid back to the pump and mix tank holding the remaining other half of the spacer. Next, open the side entry valves into the control head and pump the required nitrogen volume for the kick simulation into the top of the drillpipe. (Refer to Figure 11-1b.) Pump until the U-tube pressure between the drillpipe and casing annulus and the pit level gain relative to the level before introducing the nitrogen, indicate that the desired volume of gas is in the top of the drillpipe. Record the U-tube pressure. (The U-tube pressure is the static pressure in the nitrogen lines after injection stops.) Register the new pit level and the increase caused by the nitrogen at the top of the drillpipe. Volume of nitrogen as per example case to follow.

4. After the nitrogen is injected, close the side entry valves at the control head. Nitrogen company will bleed system back to the trucks but leave the lines connected to the control head on the floor.

5. Refer to Figure 11-1c. Pressure up surface circulating

equipment to match the U-tube pressure at the top of the drillpipe in the control head after the gas was introduced. Open the safety valve above the control head and the lower kelly valve and pump the remaining spacer in the mix tank (tail) behind the nitrogen. Volume as per example to follow. Register the pit level with the added spacer fluid volume and nitrogen in the drillpipe. Switch the pumps to the rig mud system and pump the spacer and nitrogen to the bit and to the annulus at specified rate (as per example to follow). Using the drillpipe to deliver the gas to the bottom of the well to create the gas kick in the annulus is only a means to get the gas in place. It is not a part of the well control procedure, which only begins when the total volume of gas is pumped into the annulus downhole.

When the gas was introduced at the top of the drillpipe, a pit gain equal to the volume of gas pumped at the top was registered. The pit gain increase caused by the gas pumped into the top of the drillpipe is the volume of nitrogen in the drillpipe at near-surface temperature and pressure conditions. As the gas is pumped down the drillpipe, it will be compressed by the increasing pressure of the mud column being pumped behind it. The initial pit gain caused by the gas added at the top of the drillpipe will begin to diminish as the gas volume in the drillpipe decreases under pressure. In order to ensure that all of the gas in the drillpipe is pumped into the annulus before initiating the shut-in sequence, the total volume of the tail spacer and the mud pumped behind the gas should be equal to the capacity of the drillpipe and drill collars that make up the string all the way to the bit, before shutting down the pumps.

When the gas reaches the bottom of the well, either in the drillpipe or annulus, its volume will be at its smallest compressed size and will be equal to the kick volume that will be used for the simulation exercise. Example: If the lead and tail spacer pills added to the circulating system were a total of 20 bbl, and the nitrogen injected was a total of 50 bbl at surface conditions, the pit gain before the gas was pumped downhole would be 70 bbl. If the 70-bbl gain is reduced to a net gain of only 35 bbl when the pills and gas reach bottom, all of the reduction is due to the compression of the gas. The spacer still occupies the same volume downhole (20 bbl) as it did at the surface. Therefore, the initial 50-bbl volume of gas was compressed by 35 bbl and its downhole volume is only 15 bbl. This is the size of the nitrogen gas kick at the bottom of the well at the start of the simulation procedure. (The example well case to follow will use the ideal gas law equations to determine the surface gas volume required to meet the downhole kick size desired for the simulation exercise.)

6. The flow up the annulus of the well will begin to increase at some point as the nitrogen is pumped into the annulus and begins to rise. The flow-show and pit level monitors system should both indicate flow from the well. Do not stop pumping mud into the drillpipe until all of the gas is in the annulus. (Volume of the tail spacer and mud pumped behind the gas should equal the capacity of the drillpipe and drill collars all the way to the bit.) Normally, during a kick, the first step in a well shut-in sequence would begin by pulling the string up to clear any tool joints from the BOP stack, with the pumps still running. (This is done to avoid the possibility of sticking the pipe downhole in the well with a tool joint positioned opposite a ram in the BOP stack, which would preclude the ability to use all of the preventers if needed during a well control situation.) For this exercise, in order to simulate having a tool joint and part of the kelly in the stack when the kick occurs, would have required the removal of the nitrogen injection control head and the nitrogen supply lines from the top of the drillpipe safety valve after injecting the gas. and then reconnecting the kelly saver sub back on top of the drillpipe safety valve to pump the tail spacer followed by the mud. For this drill, however, for safety reasons, to avoid making or breaking connection next to valves that would be blocking gas pressure, this step will be skipped. When the gas is pumped to bottom and the shut-in sequence begins, the top tool joint of the drill string is at the rotary table level, and there is only slick drillpipe in the stack.

7. Absent needing to clear tool joints from the BOPs, the next step will then be to shut the pumps off, confirm flow, open HCV and close annular BOP. If soft shut-in, close the open choke; if hard shut-in, the choke would be closed already.

8. Take pressure readings on drillpipe and casing side and record. (Calculate kick volume as per discussion in step 5 above.)

Since the well is cased, there are no formations open to the well inside the casing and drillpipe annulus. The pressure at the bit inside the drillpipe is equal to the hydrostatic pressure of the mud inside the drillpipe. The pressure in the annulus at the bit is the same and equal to the hydrostatic pressure of the shorter mud column in the annulus plus the gas gradient of the bubble and the shut-in pressure of the casing at the surface. The drillpipe may be on a vacuum and the casing surface pressure will be the U-tube difference between the full head of mud inside the pipe and the mud and gas combination in the annulus. If the drillpipe has pressure at the surface, it is the result of the gas bubble in the annulus rising towards the surface due to buoyancy

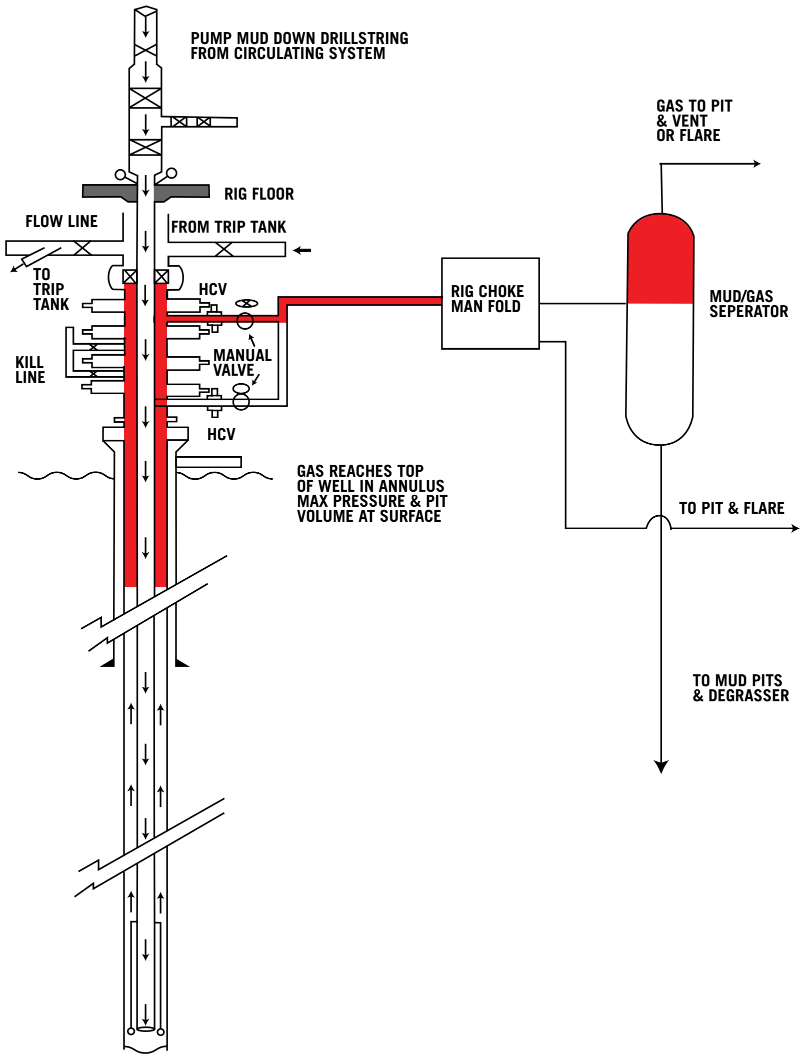


Figure 11-2: Kick simulation procedure after well shut-in and gas is circulated to the surface and through choke manifold and mud gas separator.

after the well was shut-in without allowing the bubble to expand. If the bubble moves up the hole without expanding, it will bring bottomhole pressure up the hole, increasing the casing pressure because the gas volume remains constant. The increase in casing pressure will then cause the drillpipe pressure to also rise in the shut-in well, since the ported float installed above the bit allows pressure communication from the bottom of the well through the inside of the drillpipe to the top of the drill string. If drillpipe pressure exists after shutting in the well, use this pressure as the drillpipe kick shut-in pressure to circulate out the gas. If the drillpipe pressure is greater than 500 psi, bleed it down to no more than 500 psi and use that as the shut-in drillpipe pressure. If the drillpipe is on a vacuum (most likely case), pump into the drillpipe, with the well still shut-in, until pressure response is noted. Pressuring up inside the drillpipe will induce a simulated kick underbalance condition at the bottom of the well for the well control exercise drill. The induced pressure on the drillpipe will compress the gas bubble in the annulus in a similar way as a high-pressure formation open to the underbalanced wellbore would do. No more than 200 psi at the top of the drillpipe is required to simulate the kick drill. Record the pressures on the drillpipe and casing and begin the kick circulation process.

9. To commence the process, start the pump while opening the choke to about one quarter. Bring the pump up slowly to the circulating "kill rate" while keeping the casing pressure at the same initial shut-in pressure reading by adjusting the choke on the annulus.

10. When the pump reaches the circulating "kill rate," switch to the drillpipe pressure reading and adjust the choke to maintain the drillpipe pressure at the slow, "kill rate" circulating pressure, plus the initial shut-in pressure reading on the drillpipe, plus an extra 50 psi for overbalance safety factor. This circulating rate and drillpipe pressure must be maintained constant by adjusting the choke until the kick has been circulated out. Keeping the drillpipe surface pressure and rate fixed will maintain the bottomhole pressure constant while circulating the influx out of the hole.

Pressure on the annulus (casing side) will continue to increase as the bubble is allowed to expand as it is circulated up the hole, and there is less mud filling the annulus. Pit volume will also increase as the bubble expands, pushing more mud out of the hole. The maximum casing pressure and the greatest pit gain will occur when the gas first reaches the surface, and will then begin to decrease as mud begins to replace the gas coming out of the annulus and is then vented by the separator. Figure 11-2 shows the gas at the surface going through the choke and mud separator, which is venting gas and returning mud to the circulating system. This is a good test to assess the capacity of the separator to handle the gas, to check for possible leaks and to note the direction that the venting gas will take when it is released onto the location. Under a real well kick scenario, the gas would be vented to a flare line and ignited to avoid an explosive mixture on the well location. The nitrogen gas being vented at the separator can also be diverted to the flare line if desired.

11. When the gas is out of the well, the drillpipe pressure is still being held constant at the circulation pressure plus the initial shut-in pressure and the extra 50-psi safety overbalance pressure added when circulation started. The casing pressure should be showing the initial shut-in pressure on the drillpipe plus the extra 50-psi safety overbalance that was added by pinching down on the choke, if the procedure was carried out correctly. This is because the mud hydrostatic pressure inside the drillpipe and in the annulus are now equal.

If the simulated kick were to have occurred and been circulated out in a live well with over-pressured formations open to the wellbore, the well would still be underbalanced by an amount equal the initial shut-in pressure on the drillpipe. Since the gas was circulated out with the same mud weight that allowed the kick to occur, it would take another circulation with kill weight mud of sufficient density to make up the pressure difference between the formation pressure and the hydrostatic pressure of the mud that allowed the influx to occur. The kill weight mud would then be pumped down the drillpipe and up the annulus on a schedule which would allow opening the choke as the heavier mud was circulated in place to provide the required hydrostatic pressure to overbalance the formations that caused the kick.

12. In the simulation case inside casing, there is no over-pressured formation to balance once the gas has been removed from the annulus, as might be the case when an influx occurs due to swabbing. Once the gas is out, the well control incident is over. Circulation is stopped and the well pressure can be bled off while checking to make sure that the well does not begin to flow again. If the well is dead, the BOPs can be opened and the well would then be circulated around at drilling circulating rates. (Before opening the BOPs after the kick simulation to ensure that nitrogen is not trapped under pressure below the closed preventer, drain the stack through a lower outlet.)

11.3 Example well case

The best way to explain how the kick simulation procedure described above should be designed and executed in a well is to use a well example. Figure 11-3 shows a sketch of a well where an intermediate 9 ⅝-in. casing string has been set at 12,000 ft. The drill string with a ported float installed above the bit has been run to bottom in preparation for drilling out and to proceed to drill the next section of hole. The drillstring is made up of 5-in. drillpipe and 800 ft of 6 ⅝-in. drill collars at the bottom. The mud weight in the well is 12.5 ppg. Figure 11-3a shows the drillpipe capacity to be 1.79 bbl/100 ft. The drillpipe to casing annulus capacity at the top of the well is 4.89 bbl/100 ft, and the drill collar to casing annulus capacity at the bottom of the well is 3.22 bbl/100 ft.

The chosen design case for the kick simulation procedure will be for a gas influx of 15 bbl at the bottom of the hole. The gas will be pumped to the bottom of the hole via the inside of the drillpipe. Use the following Ideal Gas Law equations to determine how much nitrogen needs be injected into the inside of the drillpipe at surface conditions so that when it is circulated down and into the annulus opposite the drill collars, it will have compressed down to 15 bbl under downhole conditions. The ideal gas equations introduced in Chapter 1, Appendix 1B, can be used to calculate the volume and pressure of a fixed mass of gas under different wellbore conditions, as might be the case when a gas kick enters a wellbore and is then circulated to the surface under a controlled pressure environment.

Ideal Gas Law equation from Appendix 1B, Equation 1B-1:

$$P_T = P_B\, e^{\left[\frac{m\,(h_T - h_B)}{ZR\,T_{avg}}\right]}$$

Equation 1B-1 can first be used to determine the pressure at

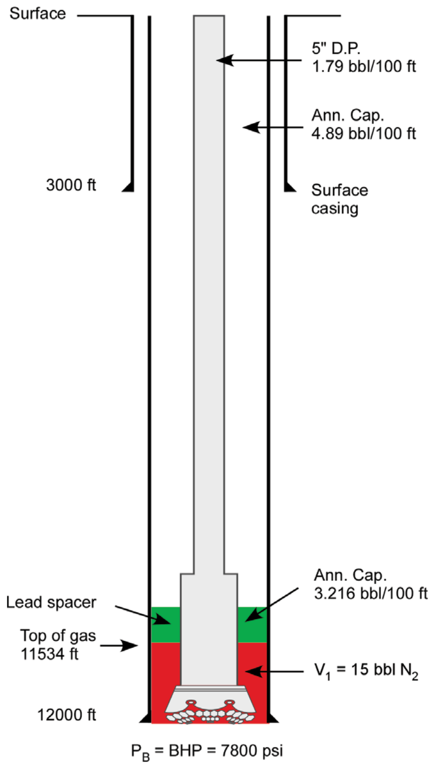


Figure 11-3a - Desired Gas Kick Volume
V_1 at downhole conditions = 15 bbl. (given)
$T_{1\ avg}$ = 716 °R
P_T top of gas = 7708 psi
$P_{1\ avg}$ = 7754 psi @ 11767 ft

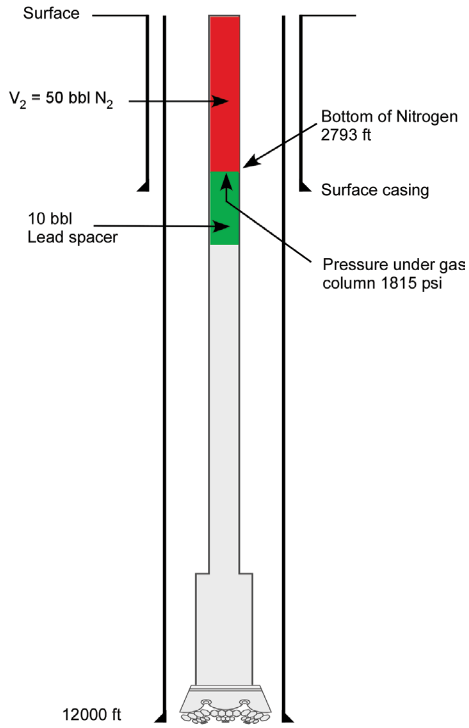


Figure 11-3b - Volume of gas
to be pumped condition V_2 to
results in 15 bbl kick downhole.
Estimate V_2 required = 50 bbls
P_B = U-tube pressure under gas = 1815 psi
Estimate $P_{2\ avg}$ = 1726 psi (midpoint)
Estimate $T_{2\ avg}$ = 561 °R (midpoint)

Figure 11-3: Example well case design: Desired gas kick volume under downhole pressure and temperature condition versus gas volume that must be pumped at the top of the drillpipe at surface condition to meet the downhole kick size objective as determined by using the ideal gas law equations

the top of a gas column, P_T, when the gas is in the annulus opposite the collars under downhole conditions when the following is known:

- Pressure at the bottom of the gas column, P_B;
- Gas properties;
- Average temperature conditions of the gas column;
- Height of the gas column;
- Compressibility factor for the gas being used for the simulated influx.

Determining P_T, pressure at the top of the gas, and knowing P_B, pressure at the bottom of the bubble on bottom, will also yield the gas gradient for the gas column, which will permit calculating the pressure of the column at any point.

P_T = Pressure at the top of the gas column, psi
P_B = Pressure at the bottom of the gas column, psi
V_1 = Volume of gas at downhole conditions, bbl
h_T = Depth to the top of the gas column, ft
H_G = Height of gas, ft ($h_B - h_T$)
h_B = Depth to the bottom of the gas column, ft
Z = Compressibility factor for nitrogen gas
R = Conversion factor for oil field units, 1,544 lb ft/mole °R
M = Molecular weight for nitrogen, lb/mole
T_{avg} = Average temperature of gas column (midpoint), °R

Refer to Figure 11-3a, showing gas in the well under downhole conditions with 15 bbl of nitrogen in the annulus between the drill collars and the casing. V_1 = 15 bbl.

Nitrogen properties: Molecular weight, M = 28 lb/mole, Compressibility factor = 1 for simplification, actual = 0.9997

Well data: Well depth = 12,000 ft. Mud weight = 12.5 ppg
Temp gradient = 1.5°F/100 ft. Surface temperature = 80°F
Temp °R = Temp. °F + 460

Height of the gas column on bottom = V_1 / annular capacity opposite drill collars

Height of gas column = 15 bbl/ (3.22 bbl/100 ft) = 466 ft

Top of the gas column, h_T = well depth – Height of gas = 12,000 ft – 466 ft = 11,534 ft

Bottom of the gas column, h_B = 12,000 ft

Midpoint of the gas column, = 12,000 ft – (466 ft/2) = 11,767 ft

P_B = well depth x mud hydrostatic head in the drillpipe to bottom = 12.5 ppg x 0.052 x 12,000 = 7,800 psi

Temp. at midpoint of gas column (average) = T_{1avg} = 80°F + (11,767 x 1.5°F/100 ft) + 460 = 716°R

Substitute in Equation 1B-1:

$$P_T = 7{,}800 \times e^{\left[\frac{28\,(11{,}534 - 12{,}000}{1 \times 1{,}544 \times 716}\right]}$$

P_T = 7,708 psi. Pressure at the top of gas column at 11,534 ft

Gas Gradient (GG) for the gas on bottom = (P_B – P_T) / Height of gas column = (7,800 psi – 7,708 psi) / 466 ft = 0.197 psi/ft

P_{1avg} = Pressure at midpoint of the gas column on bottom = P_B – (Gas Gradient x Height of gas/2)

P_{1avg} = 7,800 psi – (0.197 psi/ft x 466 ft/2) = 7,754 psi

The data and calculation above establishes the gas bubble volume, pressure and gas gradient under downhole conditions for a given mass of nitrogen gas.

The next step is to determine the volume of nitrogen, V_2, which needs be pumped into the drillpipe at surface conditions to result in 15 bbl downhole, V_1, when it is placed in the annulus between the drill collars and casing.

Ideal combined gas law equation 1B-2 introduced in Appendix 1B represents the relationship between pressure, volume and temperature that exists for a given mass of gas. For a fixed mass of gas, PV/T = C is constant and therefore $P_1V_1/T_1 = P_2V_2/T_2 = P_3V_3/T_3$, etc. If the volume, temperature and pressure are known for a gas, this equation can be used to calculate the volume of that same gas under different temperature and pressure conditions. Substitute footnoted designated data into Equation 1B-2 to correspond to case when the gas is downhole (V_1,P_{1avg},T_{1avg}), and when it was first pumped into the top of the drillpipe (V_2,P_{2avg},T_{2avg}).

Equation 1B-2 (footnoted for example case):

$P_{2avg} \times V_2 / T_{2avg} = P_{1avg} \times V_1 / T_{1avg}$ (Refer to Figure 11-2b)

Rearrange Equation to solve for V_2:

$V_2 = P_{1avg} \times V_1 \times T_{2avg}/(P_{2avg} \times T_{1avg})$

P_{2avg} = Average pressure of nitrogen column pumped to top of the drillpipe, psi

V_2 = Volume of nitrogen pumped into the top of the drillpipe, V_2, Unknown

T_{2avg} = Average temperature of column of nitrogen pumped to top of drillpipe, °R

P_{1avg} = Average pressure of nitrogen column when on bottom = 7,754 psi

V_1 = Volume of gas when on bottom = 15 bbl

T_{1avg} = Average temperature of nitrogen when on bottom = 716°R

The procedure for using this equation to calculate the volume change for the 15 bbl of gas, V_1, at bottomhole conditions to the volume V_2 that the gas will occupy at surface conditions when it is first pumped into the top of the drillpipe, is an iterative process. The process will require making an estimate of what the volume, V_2, might be in order to calculate the average temperature and pressure that it will be at under surface conditions. These estimated values are then used as the data, under surface conditions, in Equation 1B-2 to calculate V_2 to compare to the estimate that was assumed. This trial and error process is used to hone in on the volume that will closely satisfy the equation. When the calculated volume, V_2, at the surface from Equation 1B-2 closely matched the estimate assumed, the results will be valid.

Begin the process by making a first estimate for V_2: Assume that the gas on bottom will compressed to 30% of the volume pumped into the drillpipe at the top under surface conditions.

$V_1 = V_2 \times 0.30$, V_2 = 15 bbl/0.30, V_2 = 50 bbl

If 50 bbl of nitrogen is pumped into the top of the drillpipe at surface conditions, what is the height of the gas column in the drillpipe? (Refer to Figure 11-3b.)

Drillpipe capacity = 1.79 bbl/100 ft

Height of the gas column at the top of the drillpipe
= 50 bbl x (100 ft/1.79 bbl) = 2,793 ft

Midpoint of the gas column = 2,793 ft/2 = 1,396 ft

What is the pressure at the bottom of the gas column? The pressure will be the difference between hydrostatic head of the mud in the annulus outside the drillpipe and the hydrostatic head of the mud below the gas inside the pipe.

P_B = 12,000 x 0.052 x 12.5 – ((12,000 – 2,793) x 0.052 x 12.5)
= 1,815 psi

Assume that the gas gradient of the column at the surface under lower pressure and temperature conditions will also have a gradient that is only 30% of the gradient when the gas is on bottom.

Gas Gradient of column at top of the drillpipe
= 0.30 x 0.197 psi/ft = 0.06 psi/ft

Pressure at the top of the gas column:
P_{2T} = 1,815 psi – (2,793 ft x 0.06 psi/ft) = 1,647 psi

The average pressure of the gas column, P_{2avg} (pressure at the midpoint, half way up the column), when the gas is at the top of the drillpipe will be the pressure at the bottom of the gas column minus the gas gradient half way up the column:

$P_{2avg} = P_B$ – 1/2 gas height x Gas Gradient
= 1,815 psi – (2,793 ft/2) x 0.06 psi/ft = 1,731 psi

The average temperature of the gas column, T_{2avg} (temp at the midpoint, halfway up the column) when the gas is at the top will be the surface temperature plus the temperature gradient x depth to the midpoint of the gas plus 460°R:

T_{2avg} = 80°F + (1.5°F/100 ft) x 2,793 ft/2 + 460°R = 561°R

Next, calculate V_2 using rearranged Equation 1B-2 with volume, pressure and temperature data for the case when the gas was on bottom (V_1, P_{1avg}, T_{1avg}) and for the estimates of pressure and temperature made for the gas at the surface (P_{2avg}, T_{2avg}) to compare to the estimated V_2 volume assumption.

$V_2 = P_{1avg} \times V_1 \times T_{2avg} / (P_{2avg} \times T_{1avg})$

V_2 = 7,754 psi x 15 bbl x 561°R / (1,731 psi x 716°R)

V_2 = 53 bbl (Compare to estimate of 50 bbl)

This is very close to the estimate. Pump 50 bbl to conduct the kick simulation. When pumping the 50 bbl of nitrogen to the top of the drillpipe use either/or both drillpipe pressure at the top and pit level volume gain to measure the 50 bbl at surface conditions. Pumping 50 bbl will result in a slightly lower than 15-bbl kick downhole which will not be of any significance in the kick simulation exercise.

Equation 1B-2 can also be used to determine what the pressures and volume of the gas will be when it is circulated out to the top of the annulus to remove it from the well. The pressure when the gas comes to the surface on the annulus will be lower and the volume will be slightly greater than when the gas was placed in the drillpipe to pump it down the hole. The main reason is that the annular capacity at the surface between the drillpipe and the casing where the gas will come to the surface is over twice as much as the capacity of the drillpipe where the gas was first introduced at the top of the well. Since the mud weight in the circulating system has not changed, this means that the same amount of gas bubble at surface conditions in the annulus will be a shorter column and therefore result in there being more mud column hydrostatic head than when the gas was in the drillpipe. The same equations and procedure described above can be used to determine the gas volumes, pressures, and temperatures for a third case or for any other well situation that may be contemplated.

11.4 Other guidelines for designing and conducting the simulated kick drill

11.4.1 Displacement fluids for use with nitrogen kick simulation procedure

The objective for the use of displacement fluids is to reduce migration of gas due to gravity and to minimize mixing of gas and mud when the gas is pumped down the drillpipe and in the annulus. A secondary objective is to retard migration of the gas under static conditions when the pumps are shut off and when pressure and volume readings are being recorded.

The approach to achieving the objectives is to keep the formulation as simple as possible and to be easily adaptable to existing fluids, equipment and materials. To this end, when fine tuning the exercise for a given operation, it is important to ensure that the composition is compatible with the chemistry and fluid density requirements of the well. For these reasons, both the “lead” and “tail” pills should be mixed as one with the same composition and properties made by using the well fluid that is being used to drill the well and is already in the mud pits.

11.4.1.1 Guidelines

- Volume of spacer: Mix 20 bbl and use 10 for lead and 10 for the tail. Target at least 300 ft of spacer in the drillpipe and in the annulus;

- Viscosify existing mud to 10-sec, 10-min and 30-min gel strengths that are 2-3 times the existing values of base mud. (e.g., final values of 20-40 lb/100 sq ft at 120°F or 150°F) Yield point and funnel viscosity will automatically fall where appropriate for these gel strengths. High flat static gel will build rapidly and provide increased gel strength that will retard migration of gas when not pumping. The proportional increase in yield point and other low-shear-rate viscosity values that typically follow gels of this type will minimize mixing and channeling of mud and gas while displacing the nitrogen down the drillpipe;

- Use appropriate vicosifier for the mud being used. (e.g., xanthan gum-based polymers, bentonite, attapulgite for water-base mud; organo bentonite, hectorite, attapulgite dimer-trimer fatty acid viscocifiers for non-aqueous fluid, NAF. Note: a polar-activator can enhance the yield (dispersion) of organophilic clays in NAF. Pre-mix the spacer a minimum of 6-8 hours before use to provide adequate time for clay yield and to allow the pill properties to stabilize.

11.4.2 Displacement rate for nitrogen down the drillpipe

In order to pump the nitrogen down the drill string, the velocity of the fluid should be greater than the rise velocity of the gas. The simplest method to determine the fluid velocity required to displace gas down a well is to estimate the rise velocity of the gas in stagnant fluid and then pump in the opposite direction at a higher velocity. The rise velocity of the gas in a fluid depends on several factors such as the density of the gas, density of the fluid, rheological properties of the fluid, the size of the gas bubble, etc. Performing counter-current flow analysis would be very complex and most of the time unnecessary to achieve the operational objective. Two methods are presented here to provide guidelines on the required pump rate. The methods presented here are from SPE paper 4647 authored by Rader, Bourgoyne, and Ward.

The assumption in this section is that the gas rises through a stagnant fluid column and the bubble size is close to the diameter of the flow. Therefore, the velocity of the gas column can be calculated as a Taylor Bubble. The most common equation for calculating Taylor Bubble is:

$$V_{TB} = 0.54\sqrt{D_i}$$

Equation 11-1

Where:

D_i = the inner diameter of the flow area, in.
V_{TB} = Taylor Bubble velocity, ft/sec

Equation 11-1 is derived for flow of air through a column of water. The efforts for estimating the gas rise velocity in fluids other than water become more complex and consider the density of the fluids, surface tension of fluid, and rheological properties. A relatively simplified correlation based on the experimental data results is as follows:

$$V_{TB} = \left[0.23 + 0.13\,\mathrm{Log}\left(\frac{928\,\rho_l\,V_{TB}\,D_i}{\mu_l}\right)\right]\sqrt{(D_i)\,\frac{\rho_l - \rho_g}{\rho_l}}$$

Equation 11-2

Where:

D_i = diameter of the flow area, in.
μ_l = plastic viscosity of the fluid, cp
ρ_g = gas density, ppg
ρ_l = liquid density, ppg

As the density difference between the liquid and gas phase increases, the rising velocity of gas increases due to the higher buoyancy forces. The gas rise velocity is related to the Logarithm of the Reynolds number. Therefore, increasing the apparent viscosity of the fluid decreases the gas rise velocity. Assuming that the flow would be turbulent, the apparent viscosity of the fluid is estimated by plastic viscosity. The velocity of the Taylor Bubble is present in both sides of the equation and trial and error iteration process is required to determine the gas rise velocity. Usually, after 2 or 3 iterations the velocity of the gas can be determined. In most cases, the best initial value for calculating the gas rise velocity is V_{TB} = 1.2 ft/sec.

For the example well case in this section, the pressure at the surface is 1,647 psi. The density of the fluid in the drillpipe is 12.5 ppg with plastic viscosity of the fluid is 16 cp. The ID of the drill string is 4.276 in.

Using Equation 11-1 results in gas rise velocity of 1.11 ft/sec, or 67 ft/min.

$$V_{TB} = 0.54\sqrt{4.276} = 1.11 \text{ ft/sec}$$

Next use Equation 11-2 to hone-in on bubble rise velocity for fluids being used in the example well. The density of nitrogen at the top of the drillpipe at 1,647psi is 1.1 ppg. If the density of the nitrogen is not known, the data from Table 11-1 can be used. The first assumption for the gas rise velocity of 1.2 ft/sec in the right-hand side of the equation results in velocity of 1.38 ft/sec.

Table 11-1: Density of nitrogen at different pressures.

Pressure, psi	500	1,000	1,500	2,000	2,500	3,000
Density, ppg	0.35	0.7	1.0	1.4	1.7	2.0

$$\left[0.23+0.13\ \mathrm{Log}\left(\frac{928x12.5x1.2x4.276}{16}\right)\right]\sqrt{(4.276)\frac{12.5-1.1}{12.5}} = 1.38$$

The second iteration with V_{TB}=1.38 ft/sec results in 1.39 ft/sec.

$$\left[0.23+0.13\ \mathrm{Log}\left(\frac{928x12.5x1.38x4.276}{16}\right)\right]\sqrt{(4.276)\frac{12.5-1.1}{12.5}} = 1.39$$

The result of the second iteration is very close to the initial assumption and iteration was stopped. Therefore, the gas rise velocity is 1.39 ft/sec or 84 ft/min.

The calculated gas rise velocities for the example case in this section from Equations 11-1 and 11-2 were for vertical wells. In theory, the gas rise should decrease with inclination because the vertical component of buoyancy force and gravitational forces decreases. However, in reality, the gas bubble tends to cover the top section of the well rather than the total cross section of the flow area and moves up faster. The highest gas velocity is observed around 40° inclination. The rise velocity decreases after passing 45° inclination. For simplicity for wells with inclination less than 45°, for every degree of inclination consider 1% increase for the gas rise velocity. If the well deviation is greater than 45°, then consider 45% increase in gas rise velocity. For example well case, if the wellbore inclination is 30°, the gas rise velocity using the results from Equation 11-2 above would be 84 ft/min x 1.30 = 109 ft/min.

Liquid velocities greater than the gas rise velocity are required to move gas down the drillpipe. If the liquid velocity were equal to the gas rise velocity, the bubble would remain in the same position. For practical purposes to ensuring a clean sweep of gas down the drillpipe, the velocity of the fluid in the drillpipe to pump the gas to bottom should be no less than twice the gas rise velocity. For the example well, the fluid velocity in the drillpipe for a vertical well would be no less than 168 ft/min. The minimum pump rate in gallons per minute for pumping down the drillpipe can be calculated using the following equation.

$$Q = \frac{V D_i^2}{24.5}$$ **Equation 11-3**

Where:

V = fluid velocity, ft/min

Q = flow rate, gal/min

For velocity of 168 ft/min the required flow rate is 125 gal/min or 3 bbl/min.

For a deviated well at 30° of inclination, a velocity of at least 218 ft/min would be required and the flow rate would be 163 gal/min or 3.9 bbl/min.

Pumping a long viscous pill reduces the required pump rate for pushing the gas column down the drillpipe. Fluids with higher consistency index (k) and lower power law index (n) tend to move in a plug-pattern and move the gas more efficiently.

Note: When pumping a gas column down the drillpipe to place in the annulus, it is important to ensure that the entire capacity of the drill string all the way to the bit be pumped at the specified rate before stopping the pumps. Reducing the rate early could result in leaving some of the gas in the drillpipe.

11.5 Closure

In this chapter we have provided a summary of various programs and practices that many operators and contractors us to heighten and prepare the rig crews to recognize, mitigate and handle well control problems on their rigs. This training is primarily carried out by using various drills to simulate a well influx (pit level gain alarm) and by having the crews go through the steps of shutting in the well safely and properly. While these programs are excellent ways to prepare the crews we also believe that the learnings that come from the crews actually handling a controlled gas kick using nitrogen, as presented in this chapter, can be and excellent next step in helping prepare the crews in the event of a real well control problem should one ever occur.

The example problem and the use of the provided technique and mathematical equations make it possible for the engineer and rig supervisor to design a drill to fit any rig and well configuration safely and effectively. Conducting a drill on a land location can be done for a reasonable cost and the potential return value that can be achieved by the crew effectively handing just one furure well control problem correctly will more than offset the cost. With today's high cost offshore operations conducting a drill on an offshore rig can be very expensive. An alternative that can be considered in this case is to have the crews train on a land rig location. This approach can also be used to train several crews from different rigs on a single location that has been designated to conduct the drills. The procedure using nitrogen for the simulated gas influx can be safely and easily repeated as many times as desired. Once the gas has been brought to the surface and through the separator the next simulation can take place and the size of the kick can be adjusted easily if desired.

Chapter 12
Drilling Fluid Processing

TABLE OF CONTENTS

12.1 INTRODUCTION

Correct drilling fluid treatment and processing is one primary key to trouble-free, lowest-cost drilling. Other manuals are available to describe drilling fluid measurements and how to perform them. These will not be reproduced here. Some guidelines about some oft-forgotten or obscure processes will be presented to explain how some of the measurements and fluid processing will result in cheaper wells. Most of these suggestions apply to both non-aqueous drilling fluids (NADF) and water-based drilling fluids.

Many books are available about how to remove drilled solids, but this aspect of drilling operations seems to be mostly ignored. For example, the "SPE Petroleum Engineering Handbook, Volume II: Drilling Engineering" lacks a chapter on the subject (only a very short section within a chapter that discusses solids settling). Yet, this is the secret to trouble-free, fast drilling, and the guidelines are simple.

Good solids control starts with proper removal of cuttings as they are created by the drill bit. These cuttings must be transported to the surface by the drilling fluid. If the carrying capacity of the drilling fluid is insufficient, the cuttings become too small for shale shakers to remove. After the cuttings reach the surface, the drilled solids removal equipment must be sized correctly and plumbed correctly to remove as many undesirable particles as possible.

To ensure removal of cuttings from the bottom of the hole as expeditiously as possible, a method to maximize the hydraulic power or the hydraulic impact of the drilling fluid was presented in Chapter 4.

The guidelines in Chapter 6 for cuttings transport can be used to bring the cuttings to the surface as expediently as possible. Large cuttings can be removed with the main shale shaker if they are transported correctly. Cuttings that tumble will cause a build-up of small drilled solids that cannot be easily removed from the drilling fluid. Small solids increase plastic viscosity (PV) of the drilling fluid and have a very negative effect on drilling operations. Increasing PV will decrease the carrying capacity of the drilling fluid and decrease the founder point of the drill bit. The small solids will also prevent the filter cake from being thin, slick, and compressible. Many drillers fail to appreciate the value of a low PV. For example, one common misconception about NAF is the opinion that it "tolerates" drilled solids more readily than a water-based fluid. It is true that the yield point of NAF does not change radically when drilled solids are incorporated into the fluid. Drilled solids still affect the plastic viscosity and filter cake deposition. The practice of using the same NAF drilling fluid in a series of wells should be carefully evaluated. Hole problems that are prevalent because of drilled solids will appear in these wells. This might be called invisible nonproductive time (NPT). Stuck pipe and lost circulation are easily visible NPT; lower drilling rates, poor cement jobs, drilling fluid dilution, and other associated problems contribute to invisible NPT.

12.2 Purpose of drilled solids removal

Drilled solids increase plastic viscosity which, in turn, will decrease the founder point. Drilled solids affect the yield point of water-based drilling fluids much more significantly than they affect an oil-based drilling fluid. The impression, therefore, is that oil-based drilling fluids, or NAF, can tolerate drilled solids more easily than water-based drilling fluids can. The problem is that they affect the founder point — which is seldom determined. The founder point is a function of the hydraulics available and the plastic viscosity of the fluid. A low PV increases the founder point. This is discussed in Chapter 4.

Drilled solids will also create a very bad filter cake — even in a non-aqueous fluid (NAF). Filter cake thickness does not correlate with fluid loss in NAF (or water-based drilling fluids). In a Newtonian fluid, filter cake thickness is dependent upon the fluid loss. In a Non-Newtonian fluid, drilled solids can increase the filter cake thickness while lowering the API (American Petroleum Institute) fluid loss. Although it is not an "API test", evaluate filter cake thicknesses in a high temperature high pressure (HTHP) fluid loss cell with several different pressures at room temperature. If an NAF fluid has been used in several wells, the colloidal content will have increased. The extremely large surface area which must be covered with NAF will prevent much fluid from leaving and the filter cakes will be very thick. Cement will not displace a thick filter cake.

Following weight-on-bit guidelines from bit manufacturers can have a very negative effect on economics, if hydraulics and drilled solids prevent removal of all drilled solids from beneath the bit. If the bit is drilling at half the possible drilling rate because the weight on bit is much above the founder point, the bit will wear out much sooner than it should. Combine doubling the drilling rate with three times the bit life and considerable savings are possible. In one case, a 7 ⅞-in. bit was drilling in a field that had over 2,000 wells drilled. The rig hydraulics that were being used were inadequate to clean the bottom of the hole when the "proper manufacturer-recommended" weight on bit was applied. By decreasing the bit weight, the bits lasted three times longer and drilled twice as fast. The savings were 30% of the AFE (Approved For Expenditure), which is the total sum of funds anticipated for this well. After so many wells in this field, the anticipated AFE had been very well established.

12.3 Calculation of low-gravity solids

Good solids control procedures require calculation of the concentration of drilled solids in the drilling fluid or in the discharge streams from solids removal equipment. The specific gravity, or density, of the low-gravity solids is necessary for accurate results. Many computer programs use a default number of 2.6 or 2.65 if a value is not available. If the opportunity to have the specific gravity is not available, an approximation can be made using the retort and the mud balance.

Calculations of volume % of low-gravity solids in drilling fluid can be determined with a retort and mud balance. The equation depends upon the density selected for the low-gravity solids. The equations for various densities are given below and they are derived in Appendix 12A at the end of this chapter.

In these equations:

$$(\rho_B - \rho_{LG})\, V_{LG} = 100P_W + (\rho_B - \rho_W)\, V_S - \frac{100}{8.34}\, MW$$

Where:

ρ_B is the density of the barite, 4.2 g m/cc
ρ_{LG} is the density of the low-gravity solids
ρ_W is the density of the water
V_{LG} is the volume percent of low-gravity solids
V_S is the volume percent of total solids (retort solids)
MW is the mud weight, ppg

For ρ_{LG} = 2.2 gm/cc: $V_{LG} = 50.0 + 1.60\, V_S - 6.00\, MW$
For ρ_{LG} = 2.3 gm/cc: $V_{LG} = 52.6 + 1.68\, V_S - 6.32\, MW$
For ρ_{LG} = 2.4 gm/cc: $V_{LG} = 55.6 + 1.78\, V_S - 6.67\, MW$
For ρ_{LG} = 2.5 gm/cc: $V_{LG} = 58.8 + 1.88\, V_S - 7.06\, MW$
For ρ_{LG} = 2.6 gm/cc: $V_{LG} = 62.5 + 2.00\, V_S - 7.50\, MW$
For ρ_{LG} = 2.7 gm/cc: $V_{LG} = 66.7 + 2.13\, V_S - 8.00\, MW$
For ρ_{LG} = 2.8 gm/cc: $V_{LG} = 71.4 + 2.29\, V_S - 8.57\, MW$
For ρ_{LG} = 2.9 gm/cc: $V_{LG} = 76.9 + 2.46\, V_S - 9.23\, MW$
For ρ_{LG} = 3.0 gm/cc: $V_{LG} = 83.3 + 2.67\, V_S - 10.00\, MW$

The range of calculated values of the low-gravity solids is significant, depending upon the density selected for the calculation. For example, consider a 13.0-ppg freshwater drilling fluid with retort solids reported as 20% volume. If this well is in a relatively young (geologically-speaking) formation, the density of the drilled solids could be 2.3 gm/cc. The calculated drilled solids concentration would be:

$V_{LG} = 52.6 + 1.68\, V_S - 6.32\, MW$
$V_{LG} = 52.6 + 1.68\, (20.0) - 6.32\, (13.0 \text{ ppg}) = 4\ .0\%$ vol

If this well is being drilled in very old dolomite, the density of the drilled solids could be 2.9 gm/cc. The calculated drilled solids concentration would be:

$V_{LG} = 76.9 + 2.46\, V_S - 9.23\, MW$
$V_{LG} = 76.9 + 2.46\, (20) - 9.23\, (13 \text{ ppg}) = 6.1\%$ vol

This variation in the concentration of drilled solids would indicate that one drilling fluid contained too many low-gravity solids when in reality, it did not If the drilled solids are to be maintained at a very low level (like 1-2% vol), the difference in calculated values becomes very important. If the drilled solids are maintained around 10%, the selection of low gravity solids density probably is not important.

Most drilling fluid programs use the density of 2.6 gm/cc for the calculations. In that case the low-gravity solids would be indicated to be:

$V_{LG} = 62.5 + 2.00\, V_S - 7.50\, MW$
$V_{LG} = 62.5 + 2.00(20) - 7.50\, (13.9 \text{ ppg}) = 5\%$ vol

The density of quartz is 2.65 gm/cc and could be used if most of the cuttings are sand.

12.3.1 Derivation of equation to calculate low gravity solids concentration

To develop the equation to calculate the concentration of low-gravity solids in a water-based drilling fluid, start with a mass balance equation — the total mass of the drilling fluid (or mud) is the mass of each component:

Mass of mud = mass of water + mass of barite + mass of low-gravity solids

Mass = density times volume

$$\rho_{mud} V_{mud} = \rho_W V_W + \rho_B V_B + \rho_{LG} V_{LG}$$

Where ρ is density and V is volume.

To express volumes as percentages of the total volume, multiply both sides of the equation by 100 and divide both sides of the equation by the volume of mud (V_m):

$$\frac{100\, \rho_m V_m}{V_m} = 100\, \rho_w \frac{V_W}{V_m} + 100\, \rho_B \frac{V_B}{V_m} + 100\, \rho_{LG} \frac{V_{LG}}{V_m}$$

$\frac{100\, V}{V_m}$ is the percent of water in the drilling fluid, or V_W

$$100\, \rho_m = \rho_W V_W + \rho_0 V_0 + \rho_{LG} V_{LG}$$

There are only two types of solids in the drilling fluid (barite and low-gravity solids):

$$V_S = V_B + V_{LG}$$

Where V_S is the % of solids in the drilling fluid. Express the volume percent of barite in terms of the total solids V_S and the low-gravity solids V_{LG}:

$V_B = V_S - V_{LG}$

Substitute the volume % barite into the mass balance equation:

$$100\ \rho_{mud} = \rho_W V_W + \rho_B\ (V_B - V_{LG}) + \rho_{LG} V_{LG}$$

The volume % of drilling fluid (or mud) consists of volume % liquid and volume % solids:

$$100\% = V_W + V_S$$

The volume of water could be expressed:

$$V_W = 100\% - V_S$$

The expression for the volume % of water can now be substituted into the mass balance equation:

$$100\ \rho_{mud} = \rho_W (100 - V_S) + \rho_B (V_B - V_{LG}) + \rho_{LG} V_{LG}$$

Solving this equation for the volume percent low-gravity solids:

$$(\rho_B - \rho_{LG}) V_{LG} = 100\rho_W + (\rho_B - \rho_W) V_S - 100\ \rho_{mud}$$

To express the mud weight (MW) in lb/gal:

$$(\rho B - \rho_{LG}) V_{LG} = 100\rho_W + (\rho_B - \rho_W) V_S - \frac{100}{8.34} MW$$

If the drilling fluid has salt in it, the water density may be substituted by the density of the water with the salt in it:

$$(\rho_B - \rho_{LG}) V_{LG} = 100\rho_{SW} + (\rho_B - \rho_W) V_S - 12\ MW$$

Where the density of the salt water (ρ_{SW}) is calculated from the equation:

$$\rho_{SW} = 1.0 + 6.45\ X\ 10\ [NaCl] + 1.67\ X\ 10\ [KCl] + 7.6\ X\ 10\ [CaCl] + 7.5\ X\ 10\ [MgCl\ ]$$

$$\rho_{SW} = 1.0 + 6.45\ X\ 10^{-7}\ [NaCl] + 1.67\ X\ 10^{-3}\ [KCl] + 7.6X10^{-7}\ [CaCl2] + 7.5X10^{-7}\ [MgCl2]$$

Where:

[NaCl] = concentration of NaCl, mg/l
[KCl] = concentration of KCl, ppb
[$CaCl_2$] = concentration of $CaCl_2$, mg/l
[$MgCl_2$] = concentration of $MgCl_2$, mg/l

12.4 Measuring the specific gravity of drilled solids

An approximation (or a practical field process) can be used to make a better estimate of the density of drilled solids. If a representative sample of cuttings is collected from the shale shaker and washed thoroughly with the liquid phase of the drilling fluid, the solids can be dried. With NADF, cooking in a retort will provide solids with less liquid. The solids recovered when using a water-based drilling fluid can also be heated in a retort, or placed in an oven for an hour or so at 500°F.

The solids are then added to a dry mud balance until the mud balance reads the mud weight of water, 8.34 ppg. This means that the solids would weigh exactly the same amount as the mud balance cup full of water. Add water slowly to the dry solids, blending it slowly to remove air, until the mud balance cup is completely full. Weigh the slurry. The density of the cuttings can be calculated from the equation:

$$SG = \frac{8.34\ ppg}{16.68\ ppg - MW\ (ppg)}$$

This equation is derived in Appendix 12A at the end of this chapter.

12.5 Drilled solids density

To determine the density of the drilled solids at the rig, an approximate answer can be obtained by using a relatively simple procedure.

Collect representative samples of the drilled solids. One method is to capture some of the material being discharged from the shale shaker screens. This material can be washed with fresh water to remove drilling fluid and any foreign material (like barite, lost circulation material, etc.) Place the clean solids in a retort and dehydrate them using the same procedure which is used to determine the % of solids in the drilling fluid.

1. Place dry drilled solids in the mud balance cup until the scale reads the density of water (8.34 ppg or 1.0 gm/cc) with the lid on the mud cup. This step actually provides the mass of the solids. If the mud cup is full of water and has been properly calibrated, the volume of the fluid in the cup is also the weight of the fluid in the cup.

2. Carefully fill the mud cup of the mud balance with water and dry it. Determine the "mud weight" of the slurry.

3. The specific gravity of the drilled solids can be calculated from the equation: SG=1/(2–MW), where:

SG is the specific gravity of the drilled solids
MW is the slurry mud weight in gm/cc

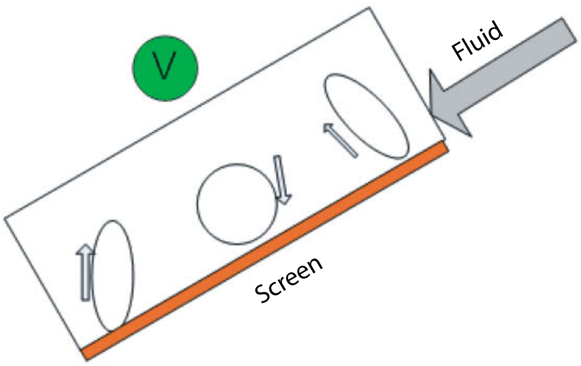


Figure 12-1: Unbalanced elliptical motion shaker.

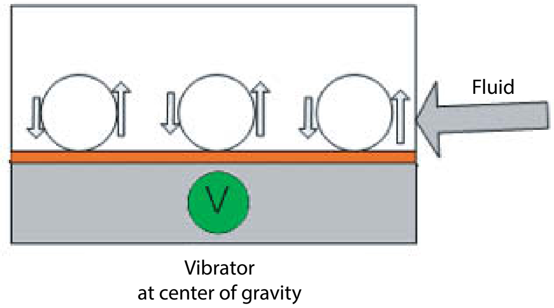


Figure 12-2: Circular motion shaker.

If the mud weight is in lb/gal, then:

$$SG = \frac{8.34 \text{ ppg}}{16.68 - \text{MW (ppg)}}$$

The equation is derived in Appendix 12A.

12.5.1 Validation of the equation

Assume that clean quartz (sand) is added to the mud balance cup and the procedure performed according to the instructions above. Quartz has a density of 2.65 gm/cc. If quartz is placed in the mud cup of the mud balance until the mud weight is indicated to be 8.34 ppg, the weight of the quartz will be the weight of water required to fill the cup. For this example, the volume of the mud cup will be 140 cc. This means that the quartz in the mud cup must weigh 140 gm. The volume of the quartz can be calculated by dividing the weight by the density or 140 gm/2.65 gm/cc, which is 52.8 cc.

The mud cup volume is 140 cc. The amount of water added is the difference between the volume of the cup and the volume of quartz, or 140 cc – 52.8 cc = 87.2 cc. The mud weight in the mud cup should be the mass of the quartz and the mass of the water divided by the volume of the mud cup. The mass of the water added is 87.2 gm and the mass of the quartz is 140 gm.

Mud weight = (140 gm + 87.2 gm)/140 cc = 1.622 gm/cc or 13.5 ppg. This should be what the mud balance would read if the procedure had been followed.

Using the 1.62 gm/cc mud weight and the equation just presented, calculate the specific gravity of the quartz:

$$SG = \frac{1}{2 - MW} = \frac{1}{2 - 1.622} = 2.65$$

This is the specific gravity of the quartz.

12.6 Solids removal equipment

Solids control equipment commonly available on drilling rigs includes shale shakers, hydrocyclones, mud cleaners, and centrifuges. These will be briefly discussed here, because much information is available about each of these. One source is the API RP13C. This has been revised and serves as a great reference for processing drilling fluid.

The first shale shakers did not actually “shake”. A wire-mesh drum was placed in the flow line so that the flow of fluid rotated the drum. Liquid easily passed through the large openings and very large drilled cuttings were rejected from the system.

12.6.1 Unbalanced elliptical shaker

The industry then selected a shaker from the mining industry. The vibrator was located above the screen and provided an elliptical motion at the ends of the shaker screen and a circular motion near the middle of the screen (Figure 12-1). The fluid at the discharge end was rotated back toward the feed end of the screen. Advertisements touted this feature as a method of better sieving the material. The screen had to be tilted downward to cause the solids to be discarded. Even then, when drilling a very sticky clay, the clay would roll back up the screen and gather more material. Usually it had to be removed manually.

12.6.2 Circular motion shaker

If the vibrator is placed at the center of gravity, the screen motion is circular (Figure 12-2). These screens required less surface area and most of the shakers were double-deck shakers. The intent was to place a coarse screen on the top deck to spread the fluid across the fine screen on the lower deck. Unfortunately, it was difficult to see when a hole appeared in the lower deck. These shakers could handle screens with openings around 177 microns but no smaller.

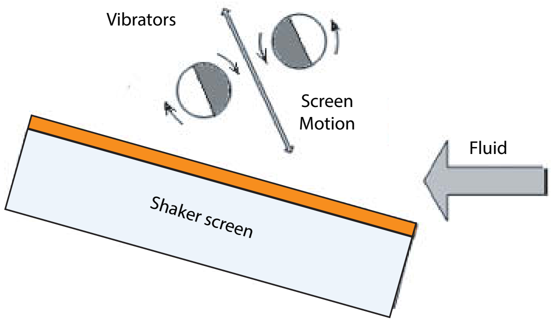


Figure 12-3: Linear motion shaker.

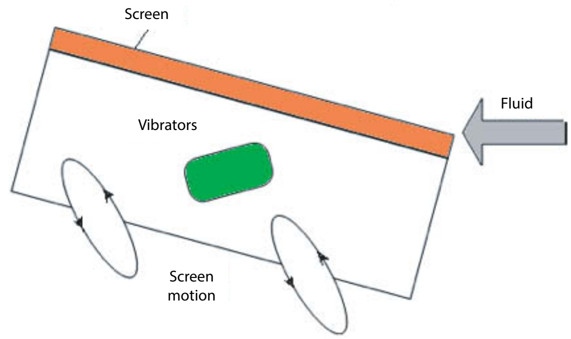


Figure 12-4: Balanced elliptical motion.

Figure 12-5: Examples of linear and balanced elliptical shakers. At left, Derrick Dual Pool 600 Shaker. Courtesy Derrick Equipment Company. At right, the M-I SWACO MONGOOSE PRO shale shaker combines balanced and progressive elliptical motion, enabling operators to switch motion "on the fly" as drilling conditions change. Courtesy Schlumberger.

12.6.3 Linear motion shaker

Linear motion on the screen was created by placing two vibrators oriented at an angle to the screen (Figure 12-3). The vibrators would reinforce the motion up or down but cancel each other as they moved toward or away from each other. These screens could handle screens as fine as 75 microns. Barite, which meets API specifications, can only have 3 % by weight of solids larger than 75 microns. The screen could be tilted upward so that a pool of liquid was formed in the upstream end of the shaker and the solids moved up the screen and off the end.

12.6.4 Balanced elliptical motion

Concern about the rapid reversal of motion on the linear shaker caused one additional development: the balanced elliptical motion (Figure 12-4). The vibrators are rotated away from the direction of movement of cuttings. This causes the linear motion to develop a slightly wider orbit. Solids are removed from a pool of liquid in the upstream end and move up the screen in the same manner as with the linear motion.

Figure 12-5 shows two examples of available commercial models.

Some shakers have one deck, some have two decks, and some have three decks with screens mounted on them (Figures 12-6 and 12-7).

Recently another option has been marketed to screen drilling fluid without shaking the screen (Figure 12-8). A continuous belt of screen cloth receives the fluid from the flow line. A vacuum beneath the screen helps the drilling fluid to flow through the screen. An airjet removes the solids from the belt after the vacuum has pulled most of the fluid through the screen.

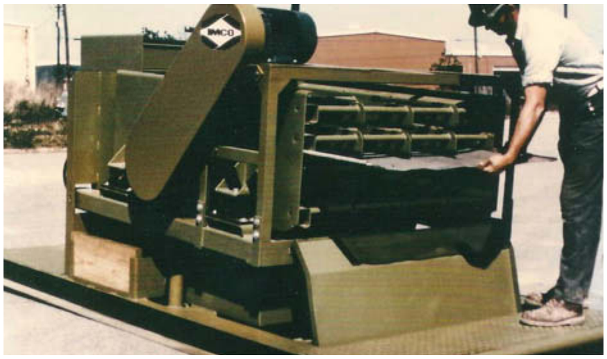


Figure 12-6: The first triple deck shaker.

Figure 12-7: Two examples of modern triple-deck shakers. At top, the Brandt VSM Multi-Sizer separator. Courtesy National Oilwell Varco. At bottom, the M-I SWACO MD-3 triple-decker shale shaker. Courtesy Schlumberger.

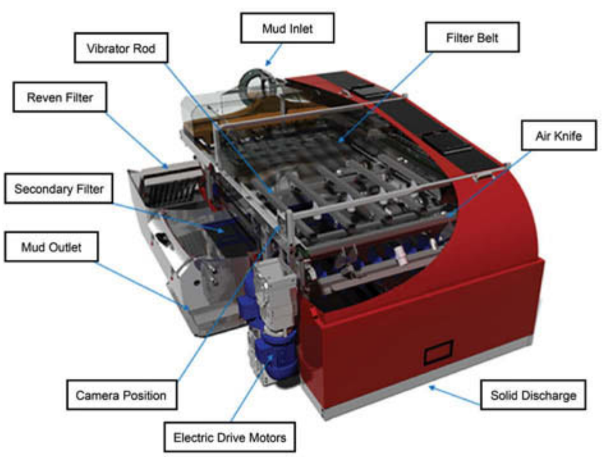


Figure 12-8: A recently developed cleaner is designed to screen drilling fluid without shaking the screen. Courtesy Cubility.

12.6.5 Hydrocyclones

Hydrocyclones are cylinders where drilling fluid is forced to spin within the cylinder. The centrifugal force of the swirling liquid moves the solids to the outside wall. The lower end of the cone is tapered so that the solids which are thrown outward toward the wall are forced to exit the lower end of the cone. In drilling operations, hydrocyclones use these centrifugal forces to separate solids in the 15-80 micron size range from the drilling fluid. This solids-laden fluid is discharged from the lower apex of the cone and the cleaned drilling fluid is discharged from the overflow discharge.

Hydrocyclones consist of an upper cylindrical section fitted with a tangential feed section and a lower conical section that is open at its lower apex allowing for "solids" discharge. The closed upper cylindrical section has a downward protruding vortex finder pipe extending below the tangential feed location (Figures 12-9 and 12-10).

Fluid from a centrifugal pump enters the hydrocyclone tangentially at high velocity through a feed nozzle on the side of the top cylinder. As drilling fluid enters the hydrocyclone, centrifugal force on the swirling slurry accelerates the solids to the cone wall.

The drilling fluid, a mixture of liquid and solids, rotates rapidly while spiraling downward towards the apex. The higher-mass solids move toward the cone wall than solids with a lower mass. Movement progresses to the apex opening at the cone bottom. At the apex opening, the solids along the cone wall, along with a small amount of fluid, exit the cone. The discharge is restricted by the size of the apex. Fluid and smaller mass particles that have been concentrated away from the cone wall are forced to reverse flow direction into an upward spiraling path at the center of the cone to exit through the vortex finder.

Hydrocyclones are designated arbitrarily by cone diameter at the inlet. Desanders (by convention, cone sizes larger than 6 in.) and desilters (by convention, cone sizes less than 6 in.) are normally used on unweighted drilling fluids. This is primarily because the cutpoint of the devices is in the size range of weighting material. Prolonged use of hydrocyclones on a weighted mud will result in a reduction in density and loss of a significant amount of weighing material.

Most balanced cones are designed to provide maximum separation efficiency when the head at the inlet is 75 ft. Fluid will always have the same velocity within the cone if the same head is delivered to the hydrocyclone inlet. Pressure can be converted to feet of head with the equation frequently used in well-control calculations:

$$\text{Head (ft)} = \frac{\text{Pressure (psi)}}{0.052 \times \text{Mud Weight (ppg)}}$$

The relationship between manifold gauge pressure and drilling fluid weight at constant 75-ft feed head is summarized in Table 12-1.

With the correct impeller in the centrifugal pump that is supplying drilling fluid to the hydrocyclones, the pressure at the manifold will automatically increase as the mud weight increases. No change in impeller diameter is needed. Study centrifugal pumps if this is not understood.

Solids, in hydrocyclones, separate according to mass, a function of both density and particle size. However, in unweighted drilling fluids the solids density is a comparatively narrow range. Size has the greatest influence on their settling. Centrifugal forces act on the suspended solids particles, so those with the largest mass (or largest size) are the first moved outward to the wall of the hydrocyclone. Large solids with accompanying liquid are concentrated at the cone wall. Smaller particles and most of the liquid concentrate in the inner portion.

Larger size (higher mass) particles, upon reaching the conical section, are exposed to the greatest centrifugal force and remain in their downward spiral path. The solids sliding down the wall of the cone, along with the bound liquid, exit through the apex orifice. This creates the underflow of the hydrocyclone.

Smaller particles are concentrated in the middle of the cone with most of the drilling fluid. As the cone narrows, the downward-spiraling path of the innermost layers is restricted by the reduced cross-sectional area. A second, upward, vortex forms within the hydrocyclone, the center fluid layers with smaller solids particles turn toward the overflow. At the point of maximum shear, the shear stress within a 4-in. desilter is in the order of magnitude of 1,000 reciprocal seconds.

The upward moving vortex creates a low pressure zone in the center of the hydrocyclone. In a balanced cone, air will enter the lower apex in counter-flow to the solids and liquid discharged from the hydrocyclone. In an unbalanced cone, a rope discharge will emerge from the cone, resulting in excessive quantities of liquid and a wide range of solids in the discard.

There are two counter-current spiraling streams in a hydrocyclone: one spiraling downward along the cone surface, and the second spiraling upward along the cone center axis. The counter-current directions together with turbulent

Table 12-1: Pressure for 75 ft of head for various mud weights.

Feed Head, ft	Mudweight, ppg	Pressure, psig
75	8.34	32.5
75	9	35
75	9	37
75	10	39
75	10	41
75	11	43
75	11	45
75	12	47
75	12	49
75	13	51

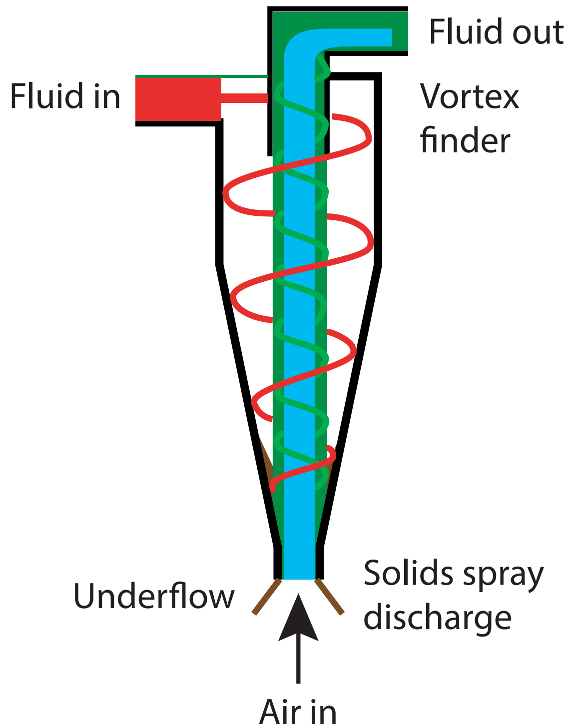


Figure 12-9: : Side view of a desilter.

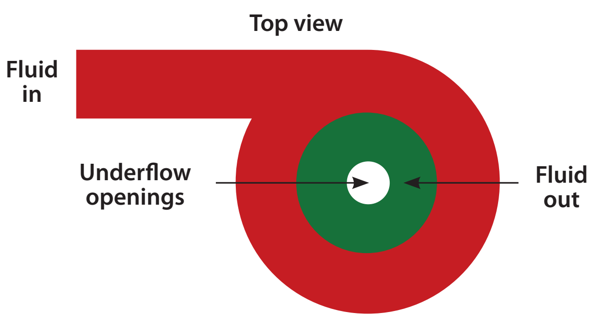


Figure 12-10: Top view of a desilter.

Table 12-2: Flow rates through hydrocyclones.		
Designation	Cone Diameter, in.	Flow rate through each cone, gpm
Desilter	2	10-30
Desilter	4	50-65
Desilter	5	75-85
Desander	6	100-120
Desander	8	200-240
Desander	10	400-500
Desander	12	500-600

eddy currents concomitant with the extremely high velocities result in an inefficient separation of particles. The two streams tend to co-mingle within the contact regions, and particles are incorporated into the wrong streams. Hydrocyclones, therefore, do not make a sharp separation of solid sizes.

Discharges from the apex of these cones are discarded when normally used on unweighted drilling fluids. Prolonged use of these cones on a weighted drilling fluid results in a significant mud weight reduction caused by discard of weighting material. When these cones are used as part of a mud cleaner configuration, the cone underflow is presented to a shaker screen. The shaker screen returns most of the barite and liquid to the drilling fluid system; rejecting solids larger than the screen mesh.

When hydrocyclones are mounted more than 5 ft above the liquid level on the mud tanks, a siphon breaker should be installed in the overflow manifold from the cones.

Rope discharge is a situation where material pours from the cone apex as a slow moving cylinder (or rope). The hydrocyclone makes inefficient solids-liquid separations. The apex velocity in rope discharge is far less than that in spray discharge. Separations are less efficient and, because of the lower velocity, fewer solids are discarded.

Rope discharge should be immediately corrected to re-establish the higher volumetric flow and greater solids separation of spray discharge. A rope discharge indicates equipment is overloaded, and additional hydrocyclones may be needed. A rope discharge can create a false sense of success as the heavier rope stream appears to contain more solids than a spray discharge. Actually, a rope discharge means that not all solids that have been separated inside the cone can exit through the apex opening. In rope discharge solids become crowded at the apex and cannot exit the cone freely. Exit rate is slowed significantly, and some solids which would otherwise be separated become caught in the inner spiral and are carried to the overflow. Dry discharge can also produce cone plugging.

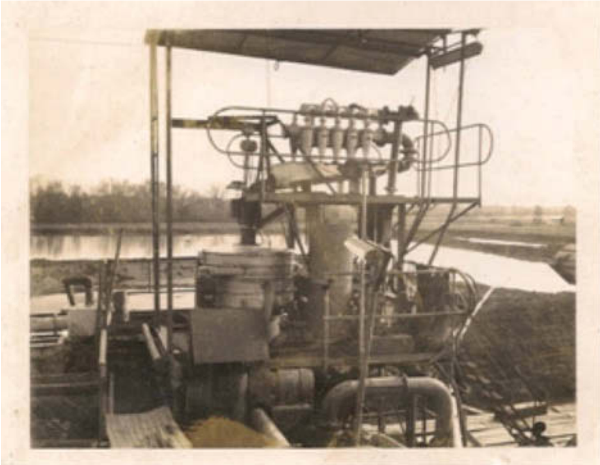


Figure 12-11a: In the first field test of a mud cleaner, ten cones were fed with a centrifugal pump driven by a diesel engine. The large "pond" in the background was the "reserve pit" and the small pond immediately behind the mud cleaner was a "duck's nest" used to store excess drilling fluid after removal from the system.

12.7 Mud cleaners

Desilters discard so much barite when processing a weighted drilling fluid that it is uneconomical to process the drilling fluid through them. (A weighted drilling fluid is defined as a drilling fluid where a commercial product has been added to increase the fluid density.) Before linear motion and balanced elliptical motion shale shakers became commercial, the finest shaker screen that could be used in the field was around an API 80. This meant that, in a weighted drilling fluid, all the solids larger than the barite (75+ microns) and the opening size in an API 80 screen (180 microns) would be left in the drilling fluid. The mud cleaner consists of a bank of hydrocyclones mounted over a shaker.

The first mud cleaner was installed on a rig at an exploration well in the Bayou Sale field in South Louisiana. Twenty Pioneer Centrifuge 4-in. hydrocyclones were mounted over a 5-ft diameter round, double-deck SWACO shaker. The test started around the first of November 1971, when the mud weight was increased to 11.0 ppg. The Miocene gas sand at 11,000 ft had never been produced. From that depth to the next casing point at 16,000 ft, Miocene gas sands had been produced. Some formations had a pore pressures from 9.0 ppg to 2.3 ppg equivalent mud weight. Some of these formations were overbalanced by as much as 6,000 psi. The finest screen that could be used on the main shakers was equivalent to 02 API 60. Using a centrifuge and dilution with the mud cleaner, the drilled solids were kept to a very low value (around 1% vol). No lost circulation or stuck pipe was experienced in this interval. Just before Christmas, the company man suggested that the equipment was not helping because they were having no problems and it could be shut down for Christmas. They thought they only had 80 ft

Figure 12-11b: A second field test was followed by one at Tilden, Texas, using potassium chloride drilling fluid. The mud cleaner removed detrimental drilled solids and also recovered a significant quantity of expensive drilling fluid.

to drill but had 200 ft. Just before New Year's Day, the company man requested that the team return and turn on that "robot thing". They drilled over 200 ft instead of the 80 ft anticipated and were having problems logging. The open hole of about 12,000 ft between the surface casing and the bottom of the hole was contributing many solids to the drilling fluid. They had to make wiper trips after every logging run and had lots of torque and drag on the drill string. So many drilled solids had accumulated in the active system that a 150 square mesh screen would barely handle all of the solids being removed by the desilters. After several circulations, the screens were changed to 200 square mesh and a significant volume of drilled solids was removed. The wiper trip indicated that the hole was once again free of a thick filter cake. Casing was run and cemented with no problem. It was also reciprocated during the cement job for the first time in that field.

The first mud cleaner was installed between two mud tanks. The centrifugal pump was driven with a diesel motor mounted on a skid. This allowed adjustments of the head at the desilter manifold by changing the rotation speed of the centrifugal pump impeller.

The modern versions of the mud cleaner look a little more professional.

A 4-in. hydrocyclone cone will process about 50 gpm at a 75-ft head. The underflow will be about 1 gpm and the remaining 49 gpm will return to the active drilling fluid system. For a flow rate of 800 gpm, the underflow would be only 16 gpm from the 16 cones needed to process all of the flow. Even the early shale shakers could process this flow rate through a fine screen.

Figure 12-12: Commercially available mud cleaners. Top: Derrick Dual Pool 600 Shaker with Mud Cleaner Option. Courtesy Derrick Equipment Company. Bottom: M-I SWACO mud cleaners combine a hydrocyclone system with a shale shaker and are designed to process the entire drilling fluid circulating volume. Courtesy Schlumberger.

When the linear motion shaker became popular on most large drilling rigs, the use of mud cleaners diminished to almost zero. Then, little by little, the mud cleaners were found to be a great insurance factor for processing all of the rig flow. This should have been obvious (but it wasn't) when considering the processing of unweighted drilling fluid. Plugged cones were (and are) common from solids that are too large to pass through the lower apex of 4 in. hydrocyclones. These solids are much larger than even solids that would be rejected by an API 20 (850 microns) screen.

12.8 Centrifuges

A decanting centrifuge has an outer cylinder that rotates from 1,600-3,000 rpm. Fluid is injected into the center of the chamber. The centrifugal motion (or centripetal acceleration) causes the larger particles to move out to the inside wall of the rotating cylinder. The particles settle through the fluid and are forced against the inside wall of the rotating chamber. For effective settling of the larger solids from the slurry, the low-shear-rate viscosity of the fluid must be decreased. Even though the fluid is moving with a high velocity around the inside of the chamber, no shear is taking place within the fluid. Drilling fluids with high yield points frequently have high values of the low-shear-rate viscosity to prevent solids from settling correctly. For these fluids, dilution is added to assist in reducing that viscosity so that solids can settle in the centrifuge.

A centrifuge separates solids by mass. Particles that have the same mass will be found together in the discard stream. In the heavy slurry, barite and low-gravity solids that have the same mass are found together. The very light particles, both barite and low-gravity solids, will be found together if they have the same mass. In other words, this is not a "barite recovery" machine. In a weighted drilling fluid, a centrifuge discards the very small particles to help keep the plastic viscosity low.

The centrifuge, running properly, will separate solids into two streams: one stream (the overflow, or light slurry) will contain particles smaller than about 10 microns; the other stream (underflow, or heavy slurry) will contain particles larger than 10 microns. For an unweighted drilling fluid, the underflow, or heavy slurry, is discarded and the centrifuge acts like a super desilters. For a weighted drilling fluid, the overflow, or light slurry, is discarded to eliminate the very small solids from the drilling fluid.

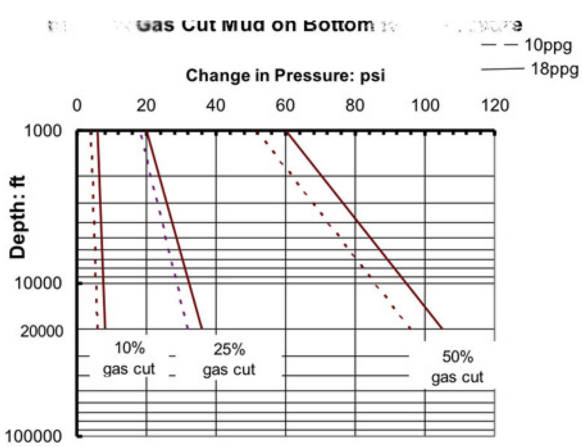


Figure 12-14: Effect of gas-cut mud on bottomhole pressure.

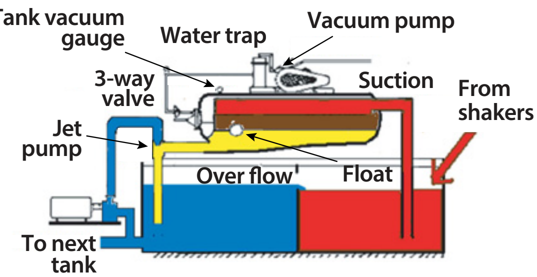


Figure 12-15: Vacuum degasser.

12.9 Degassers

Degassers are used to remove entrained air and gas from a drilling fluid. The degasser should be located in the tank system immediately after the sand trap or settling pit or immediately after the shakers if sand traps are not used.

As formation is drilled, the gas within the rock is liberated. If the gas followed Boyle's Law (a "perfect" gas), the volume increase from the bottom of a borehole to the top would be calculated from the ratio of absolute pressures. At 15,000 ft in a 12.0-ppg drilling fluid, the bottomhole pressure would be 9,360 psi or 9,375 psia. Atmospheric pressure is about 14.7 psi. The increase in volume would be (9,375 psi/15 psi) or a 625-fold increase. One gallon of gas would be 635 gallons at the surface. Gas-cut mud does not always indicate impending kicks. The bottomhole pressure is not seriously changed with a significant decrease in mud weight because of the lower mud weight from gas-cut mud.

Many think that the degasser removes gas so that the bottomhole pressure will not be reduced because of the lighter drilling fluid. Actually, by the time a gas bubble entrained in the drilling fluid reaches a depth of about 1,500 ft, the influence is small. The change in bottomhole pressures are calculated for the chart presented below. If a 10-ppg drilling fluid has a 10% gas cut, the mud weight would be 9.0 ppg. If this drilling fluid is circulated downhole the change in bottomhole pressure is less than 10 psi. If the 18-ppg drilling fluid has a 10% gas cut, the mud weight would be 16.2 ppg and the effect on bottomhole pressure is again negligible. If the

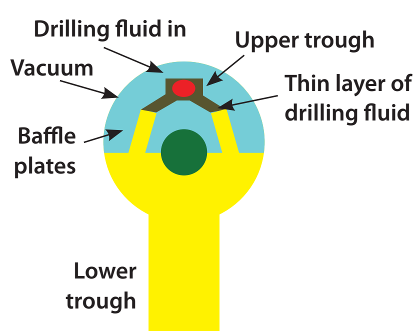


Figure 12-16: Cross section of degasser.

10-ppg drilling fluid has a 25% gas cut, it would weigh 7.5 ppg and the change in bottomhole pressure at 20,000 ft would still be only about 30 psi. An 18-ppg drilling fluid with a 25% gas cut (13.5 ppg) would also have a pressure decrease at 20,000 ft of only about 35 psi. Even a 50% gas cut of a 10-ppg drilling fluid (5 ppg) would only decrease the bottomhole pressure at 20,000 ft by about 90 psi (if you could pump it with the rig pumps). The desilters and desanders are fed with centrifugal pumps. Air or gas entrained in the feed will concentrate in the middle of the impeller and eventually prevent fluid from entering the pump.

Several types of degassers are available for drilling rigs. In the degasser shown in Figure 12-15, a vacuum pump decreases the pressure inside of a chamber. Drilling fluid is lifted into the vessel and flows down an upper trough. In Figure 12-16, the fluid is distributed in thin layers on sloping flat plates. The air or gas only has to rise a short distance to be removed from the fluid. A float in the tank controls the depth of fluid by controlling the vacuum within the chamber through a three way valve. A centrifugal pump moves drilling fluid through a jet nozzle to pull fluid from the lower trough in the degasser.

12.10 Mud tank arrangement

Every drilling rig, no matter what size, should have a drilling fluid processing plant that has three clearly defined regions: removal, addition, and suction section (Figure 12-17). These regions may be small compartments for very small drilling rigs or several tanks for the larger drilling rigs.

Independent of the size of the drilling rig, the drilling fluid processing plant should consist of three clearly defined regions: removal section, addition section, and suction section. The size of each region will depend upon the size of the hole being drilled and the depths of these holes. For example, a truck-mounted drilling rig drilling 3,000-ft (1,000-m) small diameter wells will need only a very small volume system. Larger drilling rigs drilling deeper, larger holes may need drilling fluid processing plants capable of handling 3,000 bbl or more.

12.10.1 Removal section

The removal section should be as small as possible. Most of the drilling fluid should be in the

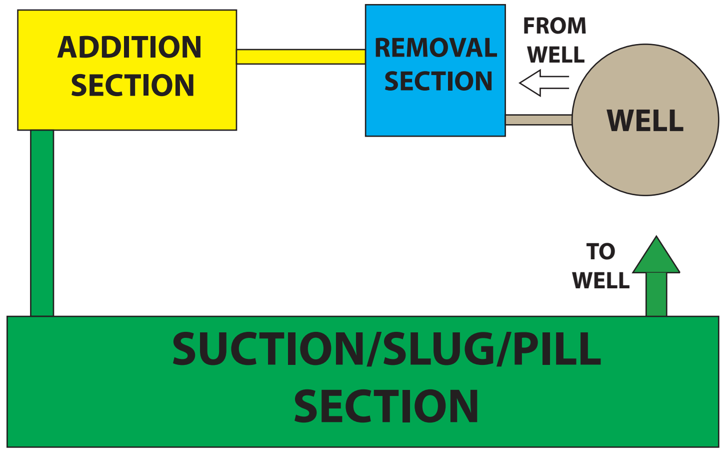


Figure 12-17: Surface drilling fluid processing plant.

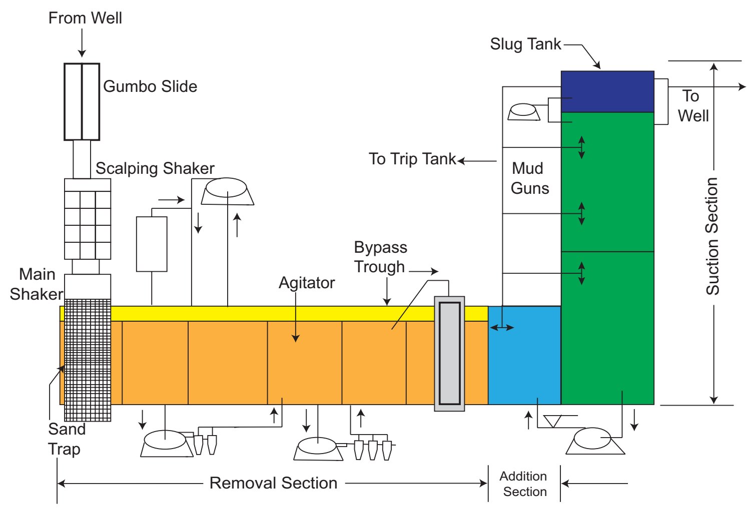


Figure 12-18: Unweighted drilling fluid processing plant.

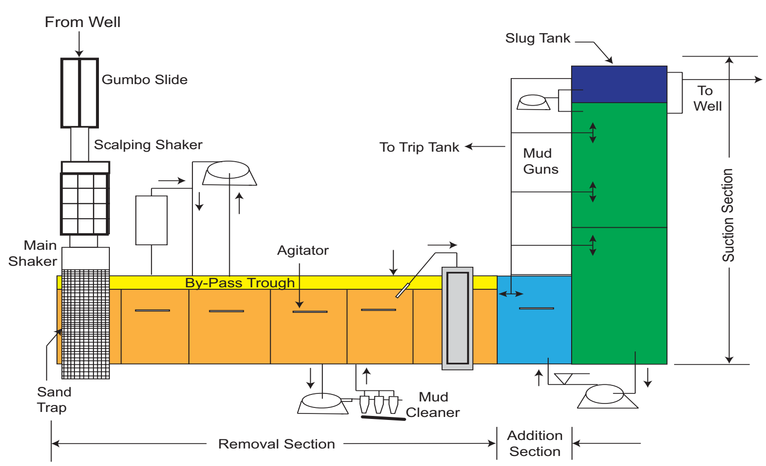


Figure 12-19: Weighted drilling fluid processing plant.

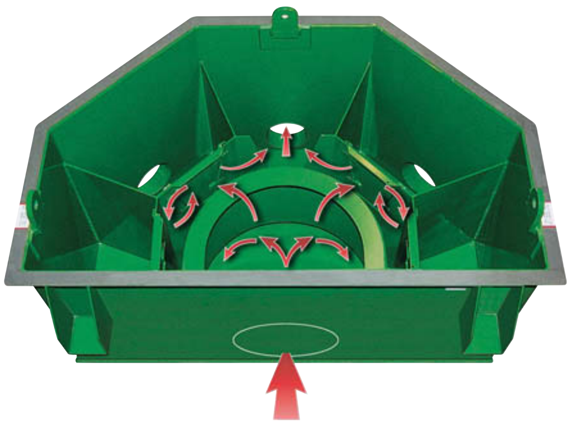


Figure 12-20: Distribution chamber. Courtesy Derrick Equipment Company.

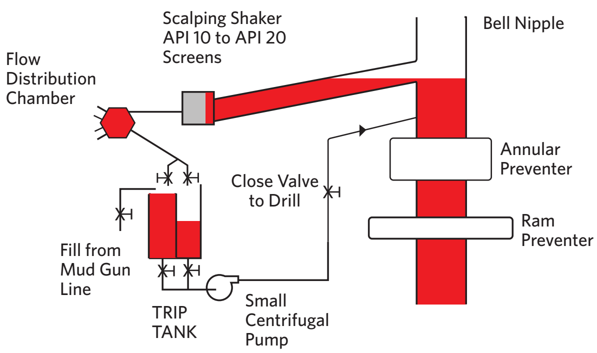


Figure 12-21: Using the distribution chamber with the trip tank.

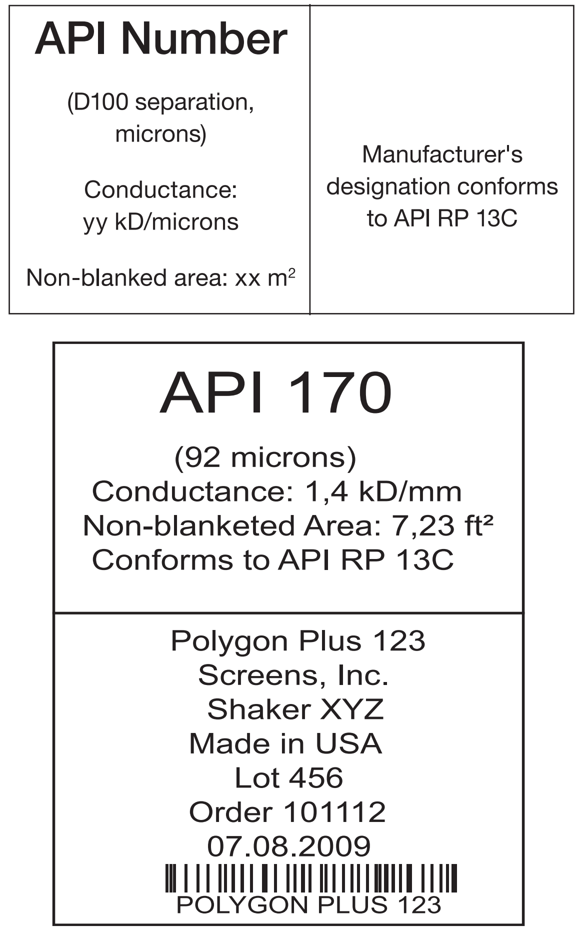


Figure 12-22: Labeling of American Petroleum Institute (API) mesh screens.

suction compartments, uniformly blended and ready to be pumped downhole.

Drilling fluid flowing down the flow line is processed through scalping shakers first. These shakers should have very coarse screens. Scalping shakers remove very large cuttings and solids which have sloughed into the hole before the fluid is screened by the main shaker. Measurements have shown that more solids are removed if the scalping shakers are dressed with large opening screens (such as API 20 or AP 30 screens). Trying to screen the drilling fluid through finer screens seems to break solids apart so they cannot be removed with API 170 or API 200 screens.

The drilling fluid enters a distribution chamber which can be used to distribute the flow equally to all main shale shakers. This replaces the back tanks of shale shakers which cause many mud systems to be used incorrectly. Derrickmen frequently dump shale shaker back tanks into the “settling pits” before a trip” If drilling fluid dries on a screen during a trip, the screens usually have to be replaced because of plugging. Unfortunately, drilling fluids currently in use are designed to prevent settling. These cuttings progress downstream and plug all of the hydrocyclones when drilling is resumed.

The distribution chamber can also be used to provide a circulation chamber for trip tanks. While pulling pipe, drilling fluid can be circulated into the top of the well and overflow down the flow line. A valve near the bottom of the distribution chamber can be opened to allow excess drilling fluid to continuously flow back into the trip tank (Figure 12-21).

The removal section could have a small volume. All undesirables are removed in this section: drilled solids and gas. The solids removal starts with gumbo busters (where needed) and shale shakers.

All screens should be labeled with the correct API labels (Figure 12-22). Screen manufacturers were labeling their screens with a variety of different numbers because they were not all using the same method to determine “mesh”. Mesh refers to the number of openings per inch in each direction. For example, a 20 x 40 mesh would mean that the screen had 20 openings in one direction and 40 openings in the oth-

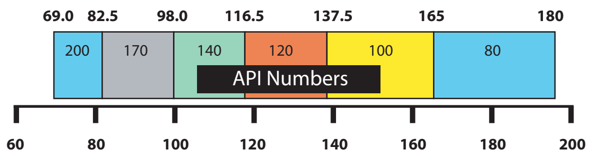


Figure 12-23: Micron range sizes for various API numbered screens.

er direction. Usually a "'60 mesh" screen implied that there were 60 openings in each direction. Unfortunately, one enterprising company labeled one 20 x 40 mesh screen as a B60. Although It was not listed as a "60 mesh" screen, most rig hands interpreted it to be 60 mesh. This screen could obviously handle a larger flow rate than a regular 60 mesh because the openings were so much larger. Salesmen concentrated on that feature instead of solids removal. Some screens examined by the API committee that were labeled 175 mesh could not stop a 100 mesh particle from passing through.

An American Petroleum Institute (API) task group addressed this problem and produced a new API RP13C document. Since the document was also planned for the International Standards Organization (ISO), the variable of "openings per inch" would have to be translated into a metric unit. The metric equivalent would probably be very confusing to rig hands. API RP13C reports openings in equivalent square openings from the American Society for Testing and Materials (ASTM) E-11 Screen Specifications. This provides a method of measuring the largest openings on a screen instead of looking at the distribution of openings. Drillers are concerned with the largest drilled solids passing through the shale shaker screens. Since the openings were to be reported in metric units, the unit of microns was selected. The second number on the screen would be "an API number" which would be the alternate designation in the E-11 Specifications. This number is the "old mesh" number. For example, a screen labeled with 74 microns would also be labeled with "API 200". This screen would be equivalent to a 200 x 200 openings or a "200 mesh". The word "mesh", however, will no longer be on the label or used in describing screens.

The API RP13C screen designation test would label a screen which will retain particles larger than 69.0-82.5 microns as an API 200. A standard ASTM 200 mesh screen has an opening size of 75 microns. A screen which retains particles larger than 82.5 to 98.0 microns would be labeled as an API 170 screen. A standard ASTM 170 mesh screen has openings of 90 microns.

The screen labels would appear with the API number and the actual minimum size particle that will be captured by the screen. Thus, a screen might be labeled "API 170" and have a

Table 12-3: D100 separation and API screen number.

D100 separation, microns	API screen number
>3075 to 3675	6
>2580 to 3075	7
>2180 to 2580	8
>1850 to 2180	10
>1550 to 1850	12
>1290 to 1550	14
>1090 to 1290	16
>925 to 1090	18
>780 to 925	20
>655 to 780	25
>550 to 655	30
>462.5 to 550	35
>390 to 462.5	40
>327.5 to 390	45
>275 to 327.5	50
>231 to 275	60
>196 to 231	70
>165 to 196	80
>137.5 to 165	100
>116.5 to 137.5	120
>98.0 to 116.5	140
>82.5 to 98.0	170
>69.0 to 82.5	200
>58 to 69	230
>49 to 58	270
>41.5 to 49	325
>35 to 41.5	400
>28.5 to 35	450
>22.5 to 28.5	500
>18.5 to 22.5	635

92 micron listed as the maximum opening size in the screen. A standard ASTM 170 mesh screen would have a 90 micron opening. This is called the D100 on a cut-point curve.

A cut-point of a screen is the ratio of the weight of solids removed by the screen divided by the weight of solids presented to the screen each of a series of size ranges. For example, in the size range of 85-90 microns, if 10 lb/min of solids are removed by a screen when 20 lb/min of solids flow onto the screen, the D50 cut-point would be 85-90 microns. The curve could be completed by using the same measurements for other intervals. The curve is usually "smoothed" to make a continuous line instead of a step function. Since the current method of labeling screens involves measuring the D100, this could not be an API 200 screen. This would mean that the largest solids which will go through the screen is larger than 74 microns.

Final word about shale shaker screens: USE ONLY API LABELED SCREENS ON YOUR SHAKERS.

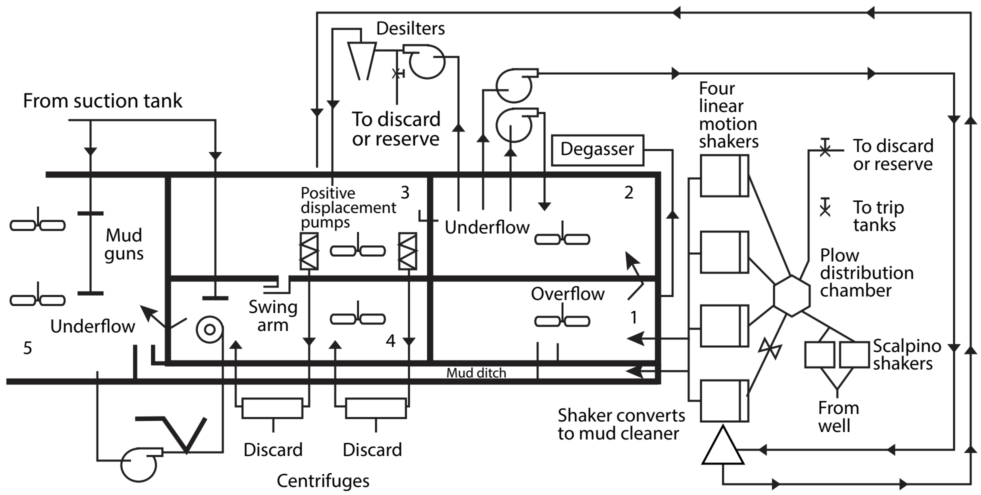


Figure 12-24: Flow diagram for removal and addition sections.

Linear-motion or balanced-elliptical-motion shale shakers remove most solids down to about 74 microns. Drilling fluid now is designed to transport cuttings in vertical wells by increasing the low-shear-rate viscosity. This means that a sand trap is no longer very effective in removing drilled solids. When API 40 and API 60 screens were used many years ago on unbalanced elliptical motion or circular motion shale shakers, many solids had time to settle in a sand trap. Short residence times and higher low-shear rate viscosities tend to eliminate sand traps as an effective solids removal tool anymore.

If the drilling rig is not equipped with a shaker (like a circular motion or unbalanced elliptical motion) that can process fluid through a fine screen, sand traps can be effective in removing large solids. Large solids have time to settle through the drilling fluid in a quiescent tank. With fine screens, the settling rates are so small that not many solids can be removed from the system. This is especially true when long extended reach wells are drilled with sufficient carrying capacity to prevent solids from settling in long sections of holes at angles greater than about 45o.

After the fluid has been sieved through a fine shale shaker screen, a degasser should be available to remove any air or gas retained in the drilling fluid. The degasser suction section should overflow into the next compartment downstream.

If API 170 or API 200 screens are used on the main shaker, most of the drilled solids that would normally be removed with desanders have been eliminated from the drilling fluid. Desanders primarily had the responsibility to decrease the solids loading on desilters. With fine screens now available on the main shakers, the desanders are no longer needed. If fine screens cannot be mounted on the shale shakers, desanders are still needed.

The desander will take suction from the degasser discharge compartment and discharge into the next compartment downstream. An underflow between compartments will allow a backflow between compartments. A backflow is needed because the desander must process more drilling fluid that the quantity entering its suction compartment.

Desilters will take suction from the desander discharge compartment and discharge into a compartment downstream. An underflow equalizer will allow backflow between compartments. If fine screens can be used, desilters should take suction from the degasser discharge compartment and discharge into the next compartment downstream. An underflow equalizer should connect the suction and the discharge compartments. More fluid should be processed through the desilters than is entering the desilters suction tank.

Mud guns are generally unacceptable in the removal section. If mud guns are supplied with fluid from the suction tank and are used to stir the desilter suction tank, the flow rate of the mud guns must be added to the desilters processing rate. Flow rates through mud guns can be approximated with the equation (derived in Appendix 12D).

Flow Rate, gpm = 19.6 [$\sqrt{(\text{head,ft})}$ (nozzle diameter, in.)^2]

If the head supplied by the centrifugal pump is 81 ft, and a single nozzle diameter is one inch, each mud gun nozzle would supply about 176 gpm to the compartment. If mud guns are used in the removal section an increase in equipment will be needed to handle all of the flow. Agitation is absolutely needed, however, in the desilter's suction tank.

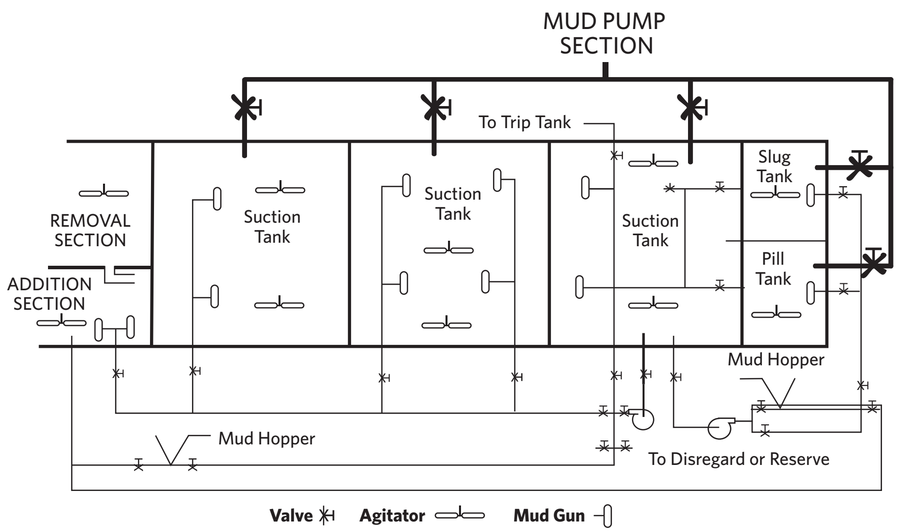


Figure 12-25: Suction tanks, slug tank, and pill tank arrangements.

Some rigs label their removal tanks as "settling pits" and do not provide agitation. THIS IS WRONG. The fluid supplied to the desilter cones should be uniform and homogeneous. This is not possible without agitation. Slugs of fluid with too many solids will plug a desilter apex and the cone will cease to remove drilled solids.

A centrifuge should take suction from the desilter's discharge compartment and discharge into the additions compartment. With an unweighted drilling fluid, the heavy slurry is discarded and the light slurry is retained. This eliminates the largest number of drilled solids. With a weighted drilling fluid, the light slurry is discarded and the heavy slurry is returned to the active system. The heavy slurry must be returned to a well-agitated region in the compartment. This heavy slurry will contain both drilled solids and barite. Sometimes this mode is erroneously called "barite recovery". It is NOT designed for recovery of barite but for the elimination of solids which have been ground into very small particles and will drastically increase PV. Economics should NOT be based on barite recovered but on the fluid properties created by the removal of the colloidal particles. (A straight pipe would recover all of the barite – but nothing would be removed. A centrifuge is designed to REMOVE drilled solids.)

All drilling fluid systems do not always need a mud cleaner or a centrifuge. When drilling a highly dispersible clay formation with a water-based drilling fluid, the mud cleaner screen may only remove barite because the drilled solids are too small. A centrifuge is needed to remove the very small drilled solids. Correspondingly, if most of the cuttings are large enough to removed by a mud cleaner screen, a centrifuge is not always needed. The decision of what equipment to use should be based on the size of the drilled solids in the drilling fluid. That will vary with drill bits, drilling fluid type and properties, and other factors.

12.10.1.1 Weighted drilling fluid

If desilters are used to process a weighted drilling fluid, too much barite would be discarded in the underflow. If an API 200 screen is mounted on a shaker to process the desilter underflow, most of the barite will pass through the screen (as well as drilled solids). The discard stream from the shaker will contain barite and drilled solids larger than 74 microns. This processing equipment is called a mud cleaner. API sand is defined as any particle larger than 74 microns. Drilling fluid should have zero % sand in it.

Frequently, rig site supervisors feel they do not need mud cleaners because the fluid is being processed through an API 200 screen on the main shaker. While this seems like a logical conclusion, it is NOT. Desilter underflow openings are about the size of a little finger, yet they are frequently plugged with solids. The solids plugging the desilters underflow orifices are much larger than the openings in the shaker screens. Even though most of the drilling fluid passes through the shaker screens, some does bypass the screen. Screens also tend to develop holes from wear and allow large solids to enter the drilling fluid system. A mud cleaner will generally remove a significant quantity of drilled solids in a normal system.

12.10.2 Additions compartment

The section after the removal section should be the place where additions are made to the system. As solids and accompanying liquids are removed from the system with the solids removal equipment, additional drilling fluid must be added to maintain a constant pit level. A constant pit level makes it easier to detect a kick.

Table 12-4: Capacity of internal upset drillpipe.				
Drillpipe size: in.	Weight: lb/ft	Capacity: l/m	Capacity: gal/ft	Capacity: bbl/1,000ft
4	11.85	6.15	0.493	11.74
4	14	5.65	0.4551	10.84
4 ½	13.75	7.94	0.639	15.22
4 ½	16.6	7.42	0.5972	14.22
4 ½	20	6.72	0.5406	12.87
5	16.25	9.85	0.7928	18.88
5	19.5	9.27	0.746	17.76
5	25.6	8.11	0.7245	17.25
5 ½	21.9	11.57	0.9314	22.18
5 ½	24.7	11.05	0.8898	21.19
6 5/8	22.2	18.64	1.5008	35.73
6 5/8	25.2	19.03	1.4517	34.56
6 5/8	31.9	16.82	1.3541	32.24

Many rigs have the mud hopper feeding into this compartment. Solids are added through the mud hopper and liquid is added through a hose. A better, more manageable system is to add whole drilling fluid into this compartment. An auxiliary tank can contain drilling fluid with the desired properties and added to the additions compartment. Occasional additions of solids may be necessary to maintain desired fluid properties. The hopper needs to be plumbed so it may continue to add material to the active system.

The fluid from the additions tank should be well-blended with the fluid in the next section – the suction/check Section. Mud guns should be used to blend and mix all of the compartments in the addition and suction section.

12.10.3 Suction section

One of the major functions of the suction section is to contain enough uniform, blended, homogeneous drilling fluid so that well control measurements are always possible. After a kick is detected and the BOP closed, the drillpipe pressure reveals the amount of underbalanced at the bottom of the hole — BUT ONLY IF THE FLUID IN THE DRILLPIPE HAS THE SAME DENSITY FROM TOP TO BOTTOM. When performing a pressure integrity test (PIT) or a leak-off test (LOT), the fluid in the drill string must have the same density from top to bottom. Otherwise it is not possible to calculate the pressure at the end of the drill string.

12.10.4 Surface volumes

The largest surface volume of drilling fluid should be in the suction section. Many rules of thumb have been proposed for creating the correct volume of drilling fluid needed on the surface when drilling a well. However, no matter what rule of thumb is used, the fluid in the drill string should have a homogeneous mud weight so that bottomhole pressures may be calculated. One suggestion, and possibly a regulation in some places, requires that one and one-half the hole volume be available on the surface. The two most common rules of thumb are presented below.

12.10.4.1 Plugged bit method

The plugged bit method determines the minimum-size drilling fluid system based on the volume required to fill the hole when pulling a plugged bit and assuming all the fluid inside the drill string is lost.

For example, a rig rated to 20,000 ft is capable of handling 5-in. drillpipe and 80,000 lb of drill collars to that depth. The drillpipe displaces 0.0243 bbl/ft, while the drill collars displace 2,718 lb/bbl. The total displaced volume is:

20,000 ft of 5-in. x 0.0243 bbl/ft = 486 bbl
80,000 lb/2,718 lb/bbl = 29 bbl
Total volume required = 515 bbl

This method gives a close approximation of the maximum volume required to fill the hole when tripping a plugged string. Usually the volume is increased by about 20%, or 100 bbl, as a safety factor.

This method indicates that the minimum-size suction section should be 615 bbl, plus a reserve to allow for kicks or lost circulation. Usually, the volume of the reserve system should be similar to that of the active system. Total system volume using the plugged bit method in this case is approximately 1,230 bbl.

12.10.4.2 Cased hole method

The cased hole method simply doubles the volume contained in the final string of casing as a guideline for sizing a suction system. For example, consider a rig rated to 15,000 ft, with 7-in. casing as the final string. The total cased volume is:

15,000 ft of 7-in. casing x 0.0390 bbl/ft = 585 bbl

Doubling this volume gives a total suction volume of approximately 1,200 bbl.

The fluid in this section should be blended to be a homogeneous slurry ready to be pumped down the hole. When the well is shut-in because of a kick, the standpipe pressure is read to determine the underbalance pressure at the bottom of the hole. The drilling fluid in the drill string must have the same mud weight from top to bottom for these readings to be have any meaning. A 4-in. diameter cylinder has a volume of 16 bbl/1,029 ft. A 4-in. diameter cylinder could represent the drill string. A 15,000-ft length of the 4-in. drill string could represent the drill string. It would have a volume of 233 bbl. Between two and three times this volume should be available in the suction section to insure homogeneous mud weight in the drill string while drilling. The capacity of some common drillpipe sizes is presented in the table for capacity of internal upset drillpipe (Table 12-4).

From a practical point of view, there are three conditions which should also be addressed:

- Lost circulation;
- Rapid drilling in large diameter holes;
- Deep drilling with large diameter drillpipe.

12.10.4.3 Lost circulation

In regions where vugular formations are prevalent, large quantities of drilling fluid may be required. In some areas where the formations cannot be sealed, drilling frequently requires a mud cap on the annulus above the lost circulation zone.

Naturally fractured formations can "drink" a large quantity of drilling fluid and the processing plant on the surface needs to be geared to blending fluid rapidly. However, many lost circulation problems are created by allowing the drilled solids to build within a drilling fluid. Very low drilled solids content has been demonstrated to circumvent lost circulation in many cases. Wells have been drilled through very permeable, depleted Miocene sands with no lost circulation (or stuck pipe) with intervals of pressure differentials as much as 6,000 psi between the wellbore pressure and the formation gas pressures. The 11.0-ppg water-based drilling fluid had less than 2% drilled solids in it.

12.10.4.4 Rapid drilling in large diameter holes

Large surface holes drilling at 200-400 ft/hr will generate a large number of cuttings. If fine screens are used, a large volume is removed as these cuttings are discarded. A 20-in. diameter hole drilling at 400 ft/hr will generate about 780 bbl of cuttings in five hours. The discard of the wet cuttings will remove about 2,340 bbl of fluid from the mud system. This quantity of fluid must be rebuilt during this period to keep the pit levels constant. On an hourly basis, 155 bbl of hole is generated. Assuming that this is ⅓ of the discard (the solids are wet when they are removed), 465 bbl must be rebuilt every hour, or new drilling fluid mixed at about 8 bbl/min. It would probably be prudent to have three times the 465 bbl, or about 1,400 bbl available in the active surface system to keep the rheology and mud weight constant while drilling.

The surface system needs to have the capability to keep up with the volume discarded while drilling, otherwise advanced planning and premixing of reserve mud should be considered. This should be planned for the worse case, which would be a bigger diameter hole where high penetration rates are common. For example, for a 14 ¾-in. hole section drilling at an average rate of 200 ft/hr and with a solids removal efficiency of 80%, the removal system will be discarding approximately 34 bbl of drilled solids per hour plus the associated drilling fluid coating these solids. Normally the drilled solids are about 30-40% volume of the discard. In most instances, about a minimum of 2-4 bbl of material will be discarded for every bbl of hole drilled. If this is the case, the volume of drilling fluid in the active system will decrease by 400 bbl/hr. If the rig cannot mix drilling fluid fast enough to keep up with these losses, reserve mud and or premixed drilling fluid should be available to blend into the active system to maintain the proper volume.

12.10.4.5 Deep drilling with large diameter drillpipe

The trend in offshore drilling is to use large diameter drillpipe to decrease the pressure loss inside the drill string and to increase the annular velocity to improve hole cleaning. However, when performing a pressure integrity test (PIT) or taking a kick, the surface pressure will be used to determine the bottomhole pressure. The drilling fluid within the drill string must be a homogeneous slurry — same mud weight from top to bottom — to be able to make accurate measurements.

For example, when a well is shut in after taking a kick, the surface pressure is measured at the upper end of the drill string. The amount of additional mud weight needed to kill the well is calculated from that pressure. If half the drillpipe is filled with a lighter, or heavier, drilling fluid, the calculation will not be possible.

The amount of fluid necessary to fill a drill string can be estimated from an approximate relationship. A square of the diameter (in inches) of a cylinder is the volume of the cylinder in bbl/1,029 ft. This can be used to quickly approximate the volume of fluid needed to fill a 14,000-ft string of 5-in. drillpipe. The inside diameter of 5-in. drillpipe is around 4.2 in. The volume of a 4.2-in. diameter cylinder is approximately 18 bbl/1,000 ft. The volume of a 14,000-ft cylinder with this diameter would be 250 bbl (14 times 18). To maintain a uniform blend of drilling fluid in the drillpipe, three to four times this volume should be available in the suction tank. For a more rigorous calculation, from Table 12-4, a 5-in., 19.5-lb/ft drillpipe, 14,000 ft long, would have an internal volume of 248.6 bbl.

Table 12-5: Height of slugs.				
Drillpipe, in.	4 ½	5	5 ½	6 ⅝
Weight, lb/ft	16.6	19.5	24.7	25.2
Capacity, bbl/1,000 ft	14.22	17.76	21.19	34.56
Height filled with 20 and 30 bbl slugs, ft				
20 bbl	1,406	1,126	810	794
30 bbl	2,110	1,690	1,415	868

12.11 Slug tank

A slug tank or pit is typically a small 20- to 50-bbl compartment within the suction section. This compartment is isolated from the active system and is available for small volumes of specialized fluid. Most drilling fluid systems should have more than one of these small compartments.

Slug tanks can be used in many ways. Obviously, they can be used to mix pills for spotting on bottom of the hole, blending lost circulation ingredients to circulate as a pill, blending viscous pills to bring cuttings to the surface, and calibrating mud pump volumetric efficiencies. Mud pumps lose volumetric efficiency when the drilling fluid contains air or gas. Usually, supercharged triplex pumps have a volumetric efficiency in the range of 97%. In one well, 6% air in the drilling fluid reduced the volumetric efficiency to 85%. The dimensions of the slug tank (minus any pipe volumes in the tank) can be used to calculate a volume of drilling fluid. While drilling, the mud pump suction can be switched from the suction tank to the slug tank. After timing a known volume removed from the slug tank, the pump suction can be switched back to the suction tank. Pumping downhole with the fluid provides back pressure on the pump discharge and an accurate volumetric measurement can be compared with the pump displacement. The volume of liquid in the slug tank needs to be calculated since the tank will contain gas and liquid. The volume fraction of gas in the drilling fluid can be calculated from the ratio of the difference between the pressurized mud weight and the unpressurized mud weight divided by the pressurized mud weight.

Slug tanks are manifolded to a mixing hopper so that solids and chemicals may be added and are used to create a heavier slurry (a slug) to be pumped into the drillpipe before trips. This makes the fluid level in the drillpipe stand at a lower level than the fluid in the annulus. This prevents drilling fluid inside the pipe from splashing on the rig floor during trips. These compartments are also used to create various pills or viscous sweeps. The main pump suction is manifolded to the slug pit(s).

The top of the fluid in the drill string while tripping should be about 100 ft below the flow line. A slug of weighted drilling fluid is pumped into the drillpipe to keep the level in the drillpipe below the flow line. The density of the slug, or the increase in mud weight above the original density of fluid depends upon the inside diameter of the drill string and the initial mud weight.

The internal volumes of various drillpipes are available in many charts. A few are presented in Table 12-5 to use as illustrations of the calculation technique.

To create a liquid level inside of the drillpipe 100 ft below the flow line, the equation below is derived in Appendix 12B:

$$MW_{slug} = \frac{MW_{orig}\,(100\text{ ft} + H_{slug})}{H_{slug}}$$

Sample calculations:

With a 10 ppg drilling fluid in a 4 ½-in. drillpipe, the mud weight of the 20-bbl slug would be:

$$MW_{slug} = \frac{10\text{ ppg }(100\text{ ft} + 1{,}406\text{ ft})}{2{,}110\text{ ft}} = 10.7\text{ ppg}$$

With a 30-bbl slug, the mud weight of the slug should be:

$$MW_{slug} = \frac{10\text{ ppg }(100\text{ ft} + 2{,}110\text{ ft})}{2{,}110\text{ ft}} = 10.5\text{ ppg}$$

With a 15-ppg drilling fluid in a 6 ⅝-in., 25.2-lb/ft drillpipe, the mud weight of a 20-bbl slug would be:

$$MW_{slug} = \frac{15\text{ ppg }(100\text{ ft} + 794\text{ ft})}{794\text{ ft}} = 16.9\text{ ppg}$$

With a 30-bbl slug, the mud weight of the slug should be:

$$MW_{slug} = \frac{15\text{ ppg }(100\text{ ft} + 868\text{ ft})}{858\text{ ft}} = 16.7\text{ ppg}$$

The increase in mud weight which is required to lower the liquid level in the drillpipe can be calculated. These increases are shown graphically in the preceding four graphs for 4 ½-in., 5-in., 5 ½-in., and 6 ⅝-in. drillpipe (Figures 12-26, 12-27, 12-28 and 12-29, respectively). Four different slug volumes are used. As expected, the increase in mud weight decreases as the volume of the slug increases. For the largest drillpipe

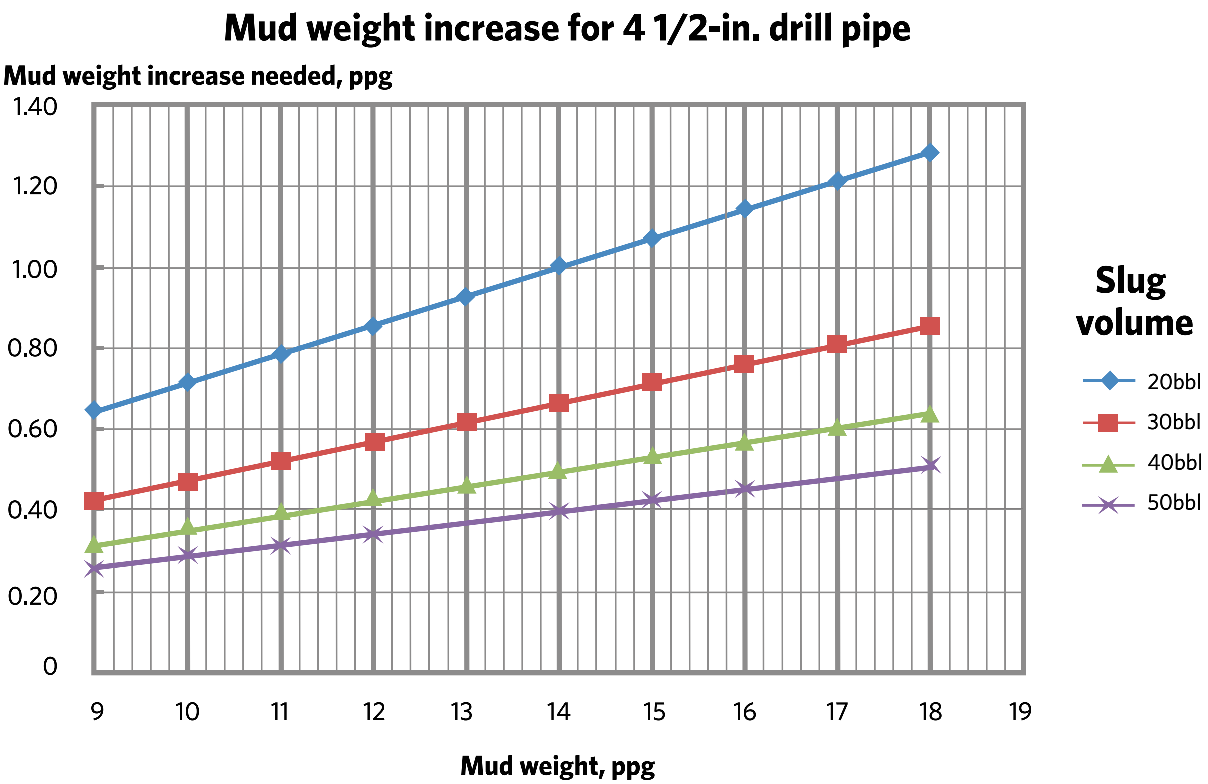


Figure 12-26: Increase in mud weight needed for slug to lower the liquid level in 4 ½-in. drillpipe to 100 ft below the flow line.

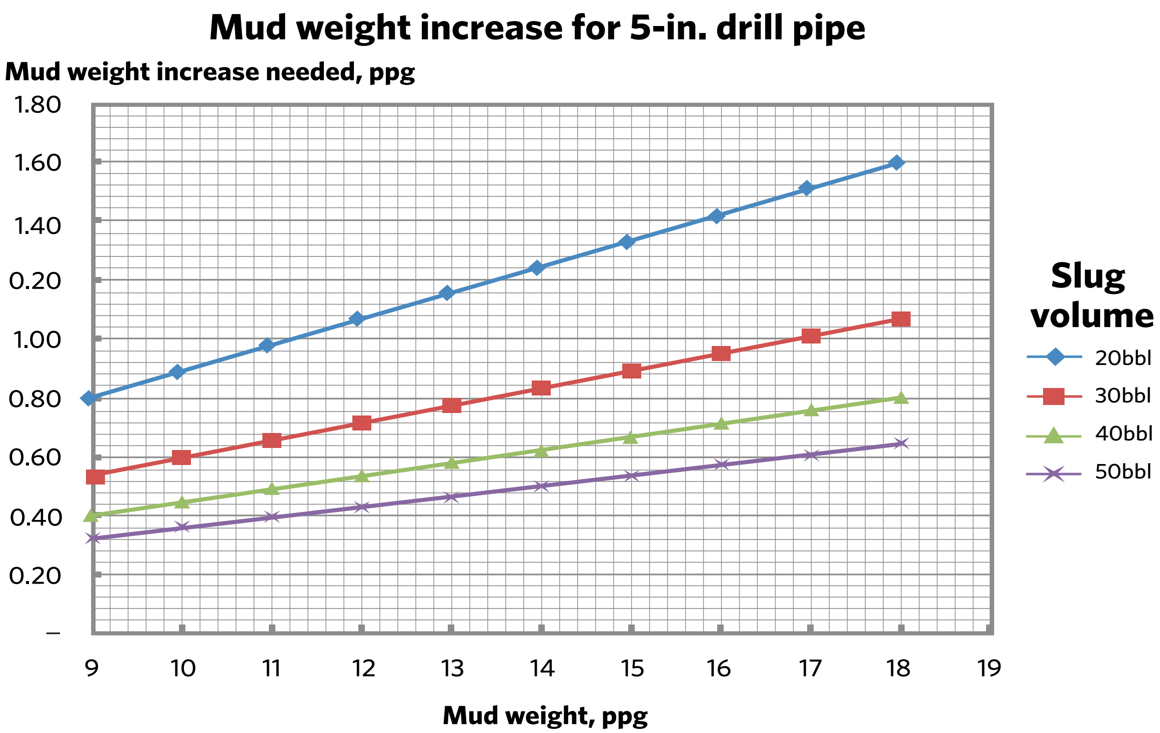


Figure 12-27: Increase in mud weight needed for slug to lower the liquid level in 5-in. drillpipe to 100 ft below the flow line.

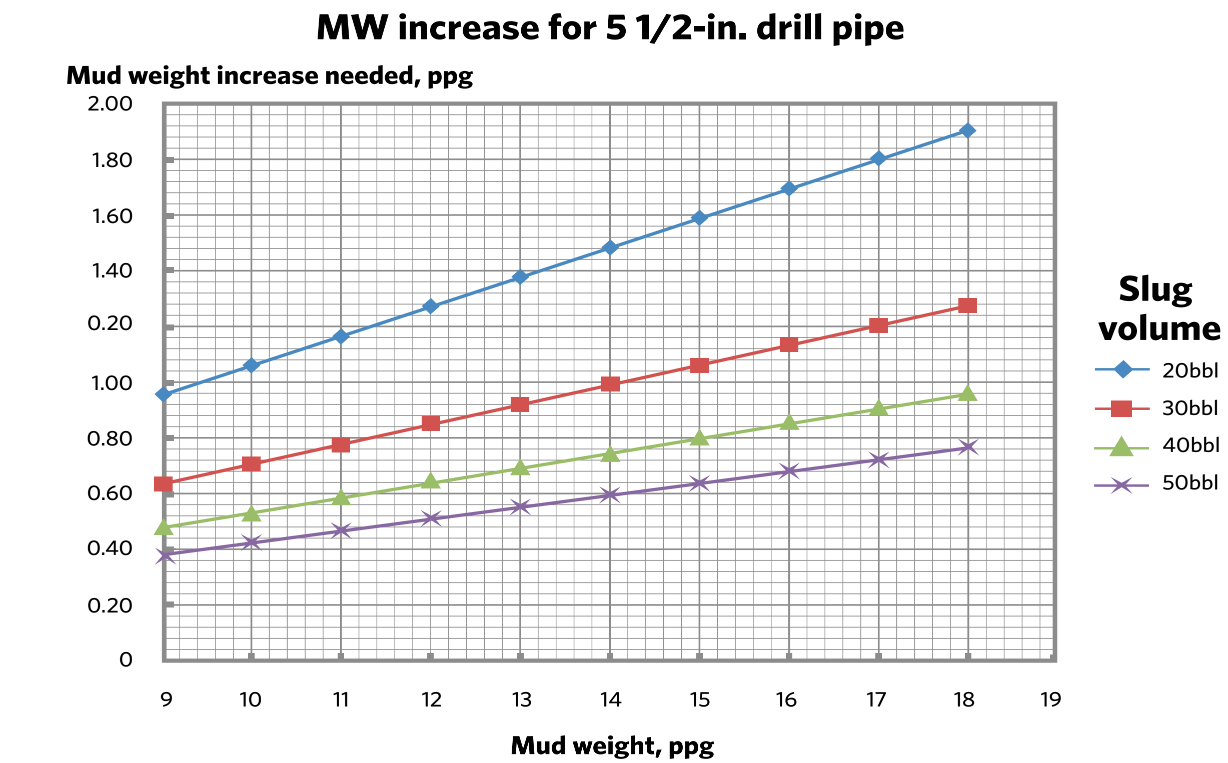


Figure 12-28: Increase in mud weight needed for slug to lower the liquid level in 5 ½-in. drillpipe to 100 ft below the flow line.

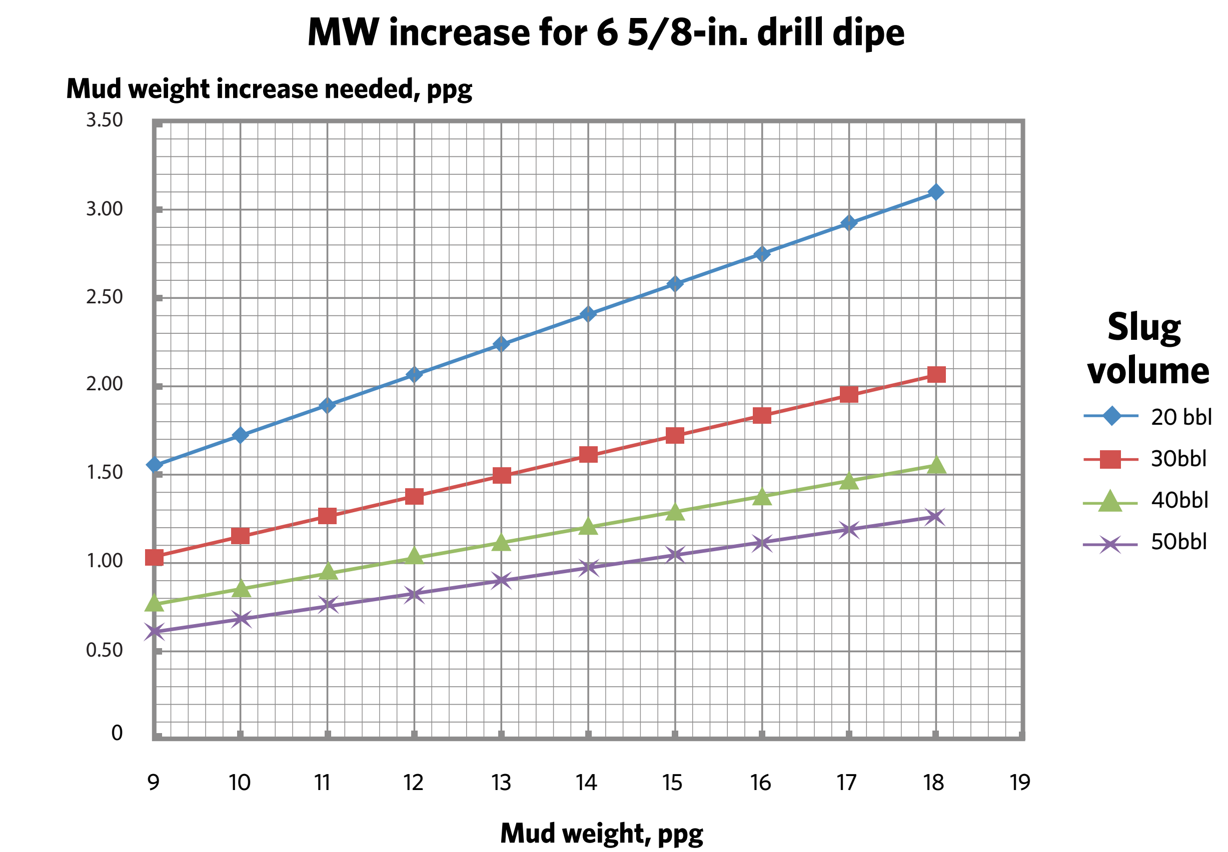


Figure 12-29: Increase in mud weight needed for slug to lower the liquid level in 5-in. drillpipe to 100 ft below the flow line.

here (6 ⅝ in.), a small slug of 20 bbl would require a mud-weight increase of 3.1 ppg, if the mud weight was 18 ppg.

The equation could also be used to determine the location of the drilling fluid surface inside of the drill string for various increases in mud weight. Many drillers use an arbitrary guideline to increase mud weight by different amounts to create the slug. Modify the equation using X instead of the 100 ft and solve the equation for X.

$$MW_{slug} = \frac{MW_{orig}\,(100\text{ ft} + H_{slug})}{H_{slug}}$$

$$MW_{slug} = \frac{MW_{orig}\,(X + H_{slug})}{H_{slug}}$$

$$X = \frac{(MW_{slug})\,(H_{slug}) - (MW_{orig})\,(H_{slug})}{MW_{orig}}$$

Calculate the depth of the top of a 20-bbl slug in a 15-ppg drilling fluid in a 6 ⅝-in., 25.2-lb/ft drillpipe, using a slug mud weight of 16 ppg.

From Table 12-5, a 20-bbl slug in a 6 ⅝-in., 25.2-lb/ft drillpipe would be 794 ft.

$$X = \frac{(16\text{ ppg})\,(794\text{ ft}) - (15\text{ ppg})\,(794\text{ ft})}{15\text{ ppg}} = 53\text{ ft}$$

In this case, the drilling fluid would probably not drain from the drill string and the crew would say the slug didn't work.

If the slug were 30 bbl, the top of the drilling fluid in the pipe would be below the flow line and still ineffective.

$$X = \frac{(16\text{ ppg})\,(868\text{ ft}) - (15\text{ ppg})\,(868\text{ ft})}{15\text{ ppg}} = 58\text{ ft}$$

12.12 Trip tanks

A trip tank is used to measure the volume of drilling fluid entering or leaving the wellbore during a trip. The volume of fluid that replaces the volume of the drill string is normally monitored on trips to make certain that formation fluids are not entering the wellbore. When one barrel of steel (drill string) is removed from the borehole, one barrel of drilling fluid should replace it to maintain a constant liquid level in the wellbore. If the drill string volume is not replaced, the liquid level may drop low enough to permit formation fluid to enter the wellbore due to the drop in hydrostatic pressure. This is known as a "kick." Usually, someone is assigned the responsibility of recording the volume required to fill the hole after each row of drillpipe is racked in the derrick. Fluid may be returned to the trip tank during the trip into the well. The excess fluid from the trip tank should be returned to the active system across the shale shakers. Large solids can come out of the well and plug the hydrocyclones if this drilling fluid bypasses the shakers.

The addition of trip tanks to drilling rigs significantly reduced the number of induced well kicks. Previously, drillers filled the hole with drilling fluid with the rig pumps by counting the mud pump strokes. (The volume was calculated for the displacement of the drillpipe pulled.) The problem here is that a certain pump efficiency is estimated in these calculations. If the mud pump is not as efficient as estimated, slowly but surely the height of the column of drilling fluid filling the hole decreases. This decreases hydrostatic head and if formation pressures are greater than the hydrostatic head of the drilling fluid a "kick" will occur. Another common cause of inducing a kick was to continue filling the hole with the same number of strokes used for the drillpipe, even when reaching the heavy-weight drillpipe, or when drill collars were pulled. Both the heavy-weight drillpipe and drill collars have more displacement per stand than the drillpipe, so a reduction in the height of the column of drilling fluid in the wellbore would occur and problems would result.

12.13 Tank arrangements

Drilling fluid should be processed through the solids removal equipment in a sequential manner. The most common problem on drilling rigs is improper fluid routing, which causes some drilling fluid to bypass the sequential arrangement of solids removal equipment. When a substantial amount of drilling fluid bypasses a piece or pieces of solids removal equipment, many of the drilled solids cannot be removed. Factors that contribute to inadequate fluid routing include: ill-advised manifolding of centrifugal pumps for hydrocyclone or mud cleaner operations, leaking valves, improper mud gun setup and use in the removal section, and routing drilling fluid incorrectly through mud ditches.

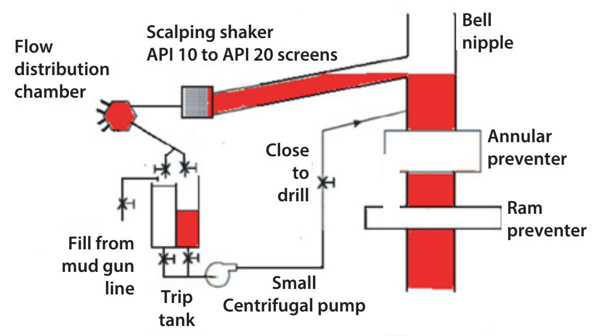


Figure 12-30: Piping and equipment arrangement.

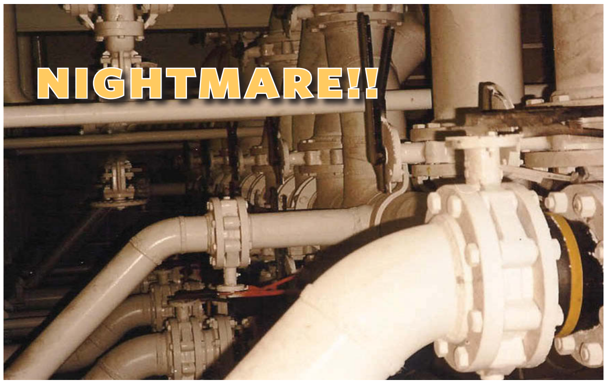


Figure 12-31: This maze of pipes will probably prevent sequential fluid processing.

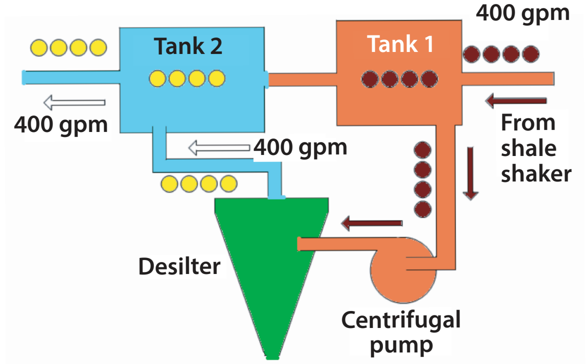


Figure 12-32: In this diagram, a desilter processes 400 gal/min of drilling fluid. By taking suction from Tank 1 and discharging the desilter-cleaned drilling fluid into Tank 2, all of the drilling fluid is cleaned.

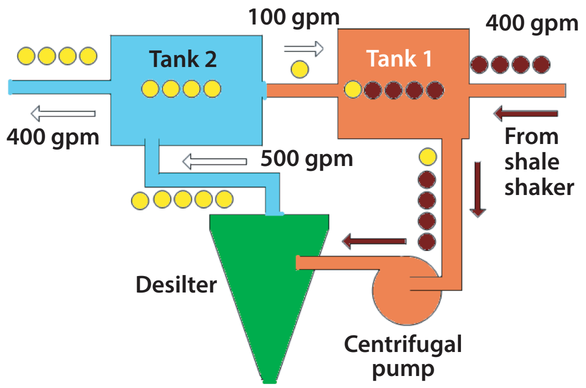


Figure 12-33: The flow rates in the well may not always be constant. To provide a degree of flexibility, the desilters should process more fluid than is arriving in the suction tank for the desilters. In the diagram above, 400 gal/min are arriving at the surface. If the desilters process 500 gal, there will be a backflow between Tank 2 and Tank 1. This ensures that all of the fluid in Tank 2 has been processed through the desilters — or 100% processing efficiency.

Each piece of solids control equipment should have its own dedicated, single purpose pump — with no routing options. When the pump is turned on, there should be only one place for the fluid to go. Hydrocyclones and mud cleaners have only one correct location in tank arrangements and, therefore, should have only one suction location. Routing errors should be corrected and equipment color-coded to eliminate alignment errors. If worry about an inoperable pump suggests allowing other pumps in the system to be used, they generally will not process the drilling fluid in a correct manner. Providing easy access to the pumps and having a standby pump in storage can save money. Common and oft-heard justifications for manifolding the pumps are "I want to manifold my pumps so that when my pump goes down, I can use the desander pump to run the desilter" or "I can pump from anywhere to anywhere with any pump", etc. These statements indicate a poor understanding of drilled solids removal. This arrangement almost automatically guarantees that the system will not process drilling fluid correctly. Having a dedicated pump properly sized and set up with no opportunity for improper operation will give surprisingly long pump life as well as processing the drilling fluid properly.

If pumps are needed for completions or for drilling fluid swap-out, they should be added to the drilling fluid processing plant. The drilling fluid processing pumps should not be used or manifolded into that system. Although this may look like a more expensive arrangement, a risk analysis of things that can go wrong should convince the most frugal drilling groups that they are well worth the additional expense. Rule: one pump, one switch, one function.

12.13.1 Calculating drilling fluid process efficiency

One of the major problems in drilled solids removal is the inability to process all of the drilling fluid. The fluid processing efficiency can be calculated by dividing the volume of drilling fluid treated by the volume of drilling fluid entering the suction compartment. This equation applies only to compartments where the drilling fluid is well-blended and homogeneous. If the drilling fluid is not well mixed, the processing efficiency will be significantly lower than the calculated value.

The fraction of drilling fluid processed, or cleaned, is the volume cleaned by the desilter divided by the volume entering the suction tank of the desilter. In this case, the answer is obvious by observing the "dirty dots" Figure 12-33.

$$\text{Processing Efficiency} = \frac{\text{flow rate entering suction compartment}}{\text{flow rate through desilters}} \times 100$$

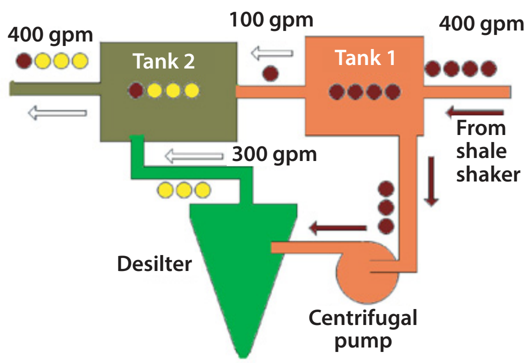


Figure 12-34: Insufficient processing.

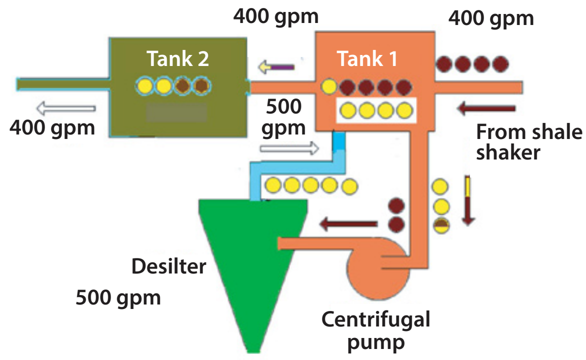


Figure 12-35: Looking at the mud "twice"?

$$\text{Processing Efficiency} = \frac{400\text{ gpm} + 100\text{ gpm}}{500\text{ gpm}} \times 100 = 100\%$$

This calculation can be tested using the next tank arrangement Figure 12-34. In this case, the flow entering Tank 1 from the well is 400 gpm; however, the desilters are processing only 300 gpm. There will be 100 gpm flowing from Tank 1 to Tank 2. Counting the "dirty dots" in Tank 2, reveals that 300 gal/min are clean but 100 gal/min have not been cleaned.

Cleaning process efficiency is the ratio of the fluid volume being cleaned divided by the volume entering the suction tank of the equipment. From the shale shaker, 400 gpm is entering TANK 1 and only 300 gpm is being processed.

Cleaning efficiency = (300 gpm/400 gpm) x 100 = 75%

In Figure 12-34, Tank 2 contains three clean dots and one dirty dot — or three out of every four gallons is being cleaned.

Usually, however, keeping an exact balance is difficult. More fluid is processed by the equipment than is flowing from the well. In Tank 2, three cleaned dots and one dirty dot indicate that only 75% of the fluid is being processed through the desilter. The equation predicts the fraction of drilling fluid processed.

Occasionally, someone on the rig will route the overflow from the desilters back into the same tank with the concept that the desilter will process the drilling fluid twice and provide a cleaner drilling fluid. Consider the case where 400 gpm is coming from the well, with the desilter cleaning 500 gpm and discharging into the tank downstream (like Figure 12-33). In this case, the desilter is processing 500 gpm, but 900 gpm (500 gpm + 400 gpm) is entering Tank 1.

The process efficiency would be: 500 gpm/900 gpm = 0.56 or 56%.

Instead of the desilter "looking at the mud twice", it only processes about one-half of the fluid entering Tank 1.

Now reducing the flow from the well to 350 gpm and processing 400 gpm should obviously provide a good processing plant — BUT not if the clean fluid from the desilter is put back into the suction tank. In this case only 56% of the drilling fluid is processed.

In Figure 12-36, notice that the desander bank (just behind the top of an agitator) is connected to the same line which is feeding the bank of desilters. What is wrong with this system? A sketch of the flow paths reveals a significant problem. The desilter feed and the desander feed lines are from the same pipe. These are in parallel and neither can process 100% of the fluid.

The total number of cones cannot be counted in the picture. Assuming that only 400 gpm of fluid was coming from the well, the desander is processing 600 gpm and the desilter is processing 500 gpm (perhaps by contract). The system looks good. However, using the equation for the fraction cleaned, the desilter is only processing about 45% of the fluid from the well.

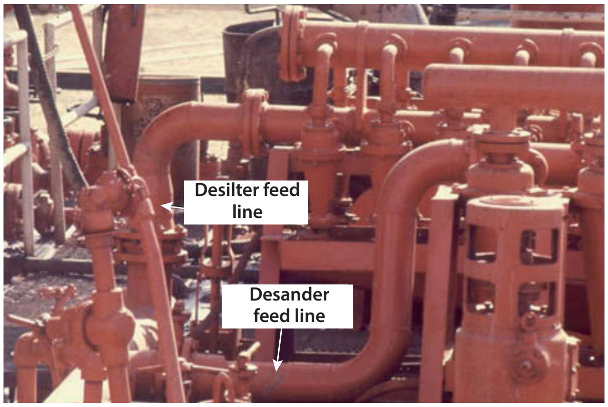


Figure 12-36: Field example of poor plumbing.

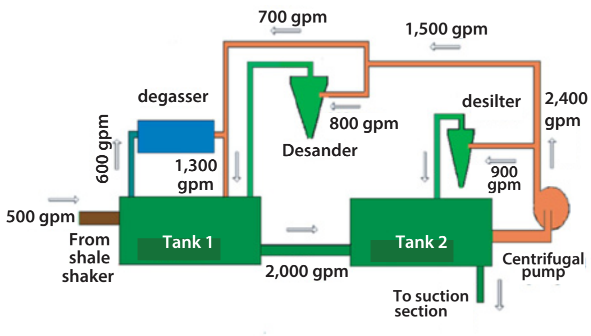


Figure 12-37: A jigsaw puzzle of valves and pipes attached to the bulkheads challenges anyone to arrange the plumbing so that the flow is correct in the removal system.

The next field example came from a location that wanted to decrease its problems with centrifugal pumps (Figure 12-37). The company man connected all the equipment up to one pump. This pump was connected into the suction tank. But only one centrifugal pump needed to be used. Several spare pumps meant that pumps could be sent in for repair without shutting the system down. As an interesting exercise, note that removing the desander from the system will increase the total fraction of fluid processed by the desilter.

Entering the suction Tank 2: the flow from the desilters (900 gpm) and the well (500 gpm), plus the flow from the desander (800 gpm), plus the flow from the educator fluid to pull the fluid through the degasser (700 gpm). The fluid flowing through the degasser is removing 600 gpm and returning the same 600 gpm for no net gain or loss. The fluid entering Tank 1 is 900 gpm + 700 gpm + 800 gpm or 2,400 gpm. The total flow entering the suction tank for the desilters is, therefore, 2,900 gpm.

Entering the suction Tank 1

From the well	+ 500 gpm
From the desander	+ 800 gpm
From the degasser	+ 1,300 gpm
Leaving the tank through the degasser	– 600 gpm
Total entering Tank 1	= 2,000 gpm

The 600 gpm into and out of the degasser is internal flow similar to the flow rate around an agitator.

Entering Tank 2:

From Tank 1	+ 2,000 gpm
From desilters	+ 900 gpm
Total	= 2,900 gpm

Tank 1 is the suction tank for desilters. The process efficiency for the desander is:

500 gpm from the well, 700 gpm from the degasser jet pump and 800 gpm from the desander, or 2,000 gpm and 900 gpm from the desilter bank; for a total of 2,900 gpm.

800 gpm/2,900 gpm = 0.28 or 28%

The process efficiency for the desilter is:

900 gpm/2,900 gpm = 0.31 or 31%

Clearly the drilled solids are going to build in this drilling fluid. The contract might read that the hydrocyclones must process at least 100 gpm more than the fluid being pumped downhole. In this case, that is insufficient to guarantee good clean drilling fluid.

Another common plumbing nightmare is found in offshore operations (Figure 12-37). Contractors are told that they need to pump from anywhere in the system to anywhere in the system. A jigsaw puzzle of valves and pipes attached to the bulkheads challenges anyone to arrange the plumbing so that the flow is correct in the removal system. Valves can leak or accidentally be left open or closed, which reduces the processing efficiency from the desired 100% to some unknown level. This increases the likelihood that excess quantities of drilling fluid will be necessary to keep the drilled solids concentration to the level needed for drilling fast, trouble-free wells. The cost of poor removal efficiency and dilution will be discussed in the next section.

Summary

Subscribe to the concept: one pump, one switch, one function in the drilling fluid processing system. For auxiliary pumping when not drilling, pumps could temporarily be connected to the system to pump from anywhere to anywhere. PLEASE SIMPLIFY PIPING IN THE DRILLING FLUID PROCESSING SYSTEM!

12.14 Dilution

Drilled solids can be controlled by removing some of the "dirty" drilling fluid and replacing the volume with clean drilling fluid containing no drilled solids. This is an expensive method.

For example, envision 2,000 barrels of drilling fluid in a well and in the mud tanks collected into a single tank (Figure 12-38). Assume the drilling fluid specifications require 5% volume drilled solids (which would be 100 bbl). After drilling 1,250 ft of a 9 ⅞-in. hole without removing any drilled solids, the volume of drilled solids would increase by about 100 bbl of solids if the formation had 15% porosity. This would double to 200 bbl the volume of drilled solids in the system.

To meet the required drilling fluid specification of 5% volume drilled solids, one half of the drilling fluid must be discarded (Figure 12-39).

If clean drilling fluid is now added to the system, the 10% volume of drilled solids in the 1,000 bbl (or 100 bbl of drilled solids) will now be spread throughout the drilling fluid system of 2,100 bbl (Figure 12-40). The new hole volume has increased by 100 bbl. This meets the specifications for the drilling fluid as required by the drilling program. If the drilling fluid costs only $20/bbl, the cost of decreasing solids in this manner is prohibitive.

After drilling only 1,250 ft of new hole, 1,000 bbl of drilling fluid must be discarded to bring the drilled solids back into a reasonable value. A lower concentration of drilled solids would be better but far too expensive when dilution is used to control drilled solids. Two costs are associated with this process: the cost of the new drilling fluid (1,000 bbl) and the cost of disposal of the dirty 1,000-bbl discard. With drilling fluid costs ranging from $30-600/bbl, the cost would be prohibitive to use this method of solids control, except for the cheapest of the cheap drilling fluids. Because it is so expensive, a compromise is frequently made to allow the drilled solids to increase to levels above 10% to 12%.

Frequently, when the solids control equipment is inadequate or, more often, plumbed incorrectly, the drilled solids will increase somewhat more slowly. If the target drilled solids concentration can be raised to a much higher concentration, less drilling fluid must be used to meet the specifications. The NPT (visible and invisible), however, will reflect the relaxation of the stringent requirements. The out-of-pocket money for treating the drilling fluid will be lower, but the total cost of the well (and long-term effects) will be significantly higher.

12.15 Effect of equipment solids removal efficiency on clean drilling fluid needed

This is a theoretical analysis of the effect of equipment solids removal efficiency and concentration of drilled solids in the discard stream. For these calculations, 100 bbl of drilled solids will report to the surface. The target drilled solids concentration is 8% volume.

12.15.1 100% Removal of Drilled Solids

If this could be accomplished and the drilled solids were 35% volume of the discard, the discard volume could be calculated:

Volume of discarded drilled solids = (0.35)(volume of total discard)

Assume 100 bbl of drilled solids arrive at the surface. If all are discarded, the total volume of discard would be:

Figure 12-38: 2,000 bbl drilling fluid containing 200 bbl of drilled solids or 10% volume.

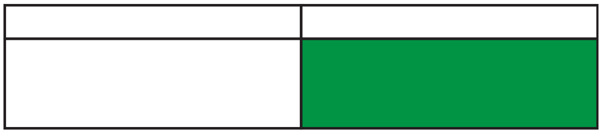


Figure 12-39: 1,000 bbl drilling fluid discarded leaving 1,000 bbl of drilling fluid containing 10% volume drilled solids.

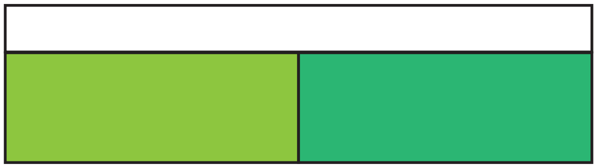


Figure 12-40: After dilution, the drilling fluid once again contains only 100 bbl of drilled solids for the 2,100 bbl.

100 bbl = (0.35)(volume of total discard)

Volume of discard = 286 bbl

The ratio of discarded volume to volume of drilled solids removed would be 2.86. In other words, for every barrel of drilled solids removed from the drilling fluid system, 1.86 bbl of drilling fluid would accompany the one barrel of drilled solids. The pit levels would drop by 286 bbl during this period and must be added to the active system to keep the pit levels constant. The concentration of drilled solids would decrease from 8% volume to a lower number (depending upon the volume of drilling fluid in the active system).

The addition of 296 bbl of clean drilling fluid will reduce the drilled solids concentration because the 186 bbl of drilling fluid discarded with the 100 bbl of drilled solids would contain 15 bbl of drilled cuttings. This reduces the total drilled solids in the drilling fluid.

12.15.2 Removal of 90% of drilled solids

Again 100 bbl of drilled solids arrive at the surface. In this case, 90 bbl of drilled solids would be discarded and 10 bbl of drilled solids would remain in the drilling fluid.

Volume of discarded drilled solids = (0.35) (volume of discard)

90 bbl = (0.35)(volume of discard)

Volume of discard = 257 bbl

Ratio of volume of discard to volume drilled solids = 2.57

In this case, 90 bbl of drilled solids and 167 bbl of drilling fluid would be discarded; or a total of 257 bbl would be required to keep the pit levels constant.

The remaining solids would need to be diluted with clean drilling fluid.

Drilled solids = (0.08)(dilution volume)

Dilution volume = 10 bbl/0.08 = 125 bbl

The dilution volume would consist of 10 bbl of drilled solids and 115 bbl of clean drilling fluid. Since 257 bbl would be required to keep the pit volumes constant and only 115 bbl would be needed to keep the pit levels constant, the total drilled solids in the active system would decrease.

12.15.3 Removal of 80% of drilled solids

Again 100 bbl of drilled solids arrive at the surface. In this case, 80 bbl of drilled solids would be discarded and 20 bbl of drilled solids would remain in the drilling fluid.

Volume of discarded drilled solids = (0.35) (volume of discard)

80 bbl = (0.35)(volume of discard)

Volume of discard = 229 bbl

Ratio of volume of discard to volume drilled solids = 2.29

In this case, 80 bbl of drilled solids and 149 bbl of drilling fluid would be discarded; or a total of 229 bbl would be required to keep the pit levels constant.

The remaining solids would need to be diluted with clean drilling fluid.

Drilled solids = (0.08)(dilution volume)

Dilution volume = 20 bbl/0.08 = 250 bbl

The dilution volume would consist of 20 bbl of drilled solids and 230 bbl of clean drilling fluid. Since 250 bbl would be required to keep the pit volumes constant and only an additional 7 bbl would be needed to keep the pit levels constant, the total drilled solids in the active system would be almost balanced. That is, the volume of clean drilling fluid needed would be almost exactly the volume which was discarded from the active system.

12.15.4 Removal of 70% of drilled solids

Again 100 bbl of drilled solids arrive at the surface. In this case, 70 bbl of drilled solids would be discarded and 30 bbl of drilled solids would remain in the drilling fluid.

Volume of discarded drilled solids = (0.35) (volume of discard)

70 bbl = (0.35)(volume of discard)

Volume of discard = 200 bbl

Ratio of volume of equipment discard to volume drilled solids = 2.0

In this case, 70 bbl of drilled solids and 130 bbl of drilling fluid would be discarded; or a total of 200 bbl would be required to keep the pit levels constant.

The remaining solids would need to be diluted with clean drilling fluid.

Drilled solids = (0.08)(dilution volume)

Dilution volume = 30 bbl/0.08 = 375 bbl

The dilution volume would consist of 30 bbl of drilled solids and 345 bbl of clean drilling fluid. Since 200 bbl would be required to keep the pit volumes constant, an additional 175 bbl would be needed to dilute the remaining drilled solids to the targeted value of 8% vol. Only a volume of 200 bbl is available after the solids removal equipment has discarded the 70% volume of solids arriving at the surface and the liquid associated with the cuttings. The actual discard would be the 200 bbl from the equipment and an additional 175 bbl to allow the remaining drilled solids to be diluted to the targeted value of 8% vol. This means that the ratio of actual volume of discard to the volume drilled would be (200 bbl + 175 bbl)/100 bbl or 3.75.

12.15.5 Removal of 60% of drilled solids

Again 100 bbl of drilled solids arrive at the surface. In this case, 60 bbl of drilled solids would be discarded and 40 bbl of drilled solids would remain in the drilling fluid.

Volume of discarded drilled solids = (0.35) (volume of discard)

60 bbl = (0.35)(volume of discard)

Volume of discard = 171 bbl

Ratio of volume of equipment discard to volume drilled solids = 1.71

In this case, 60 bbl of drilled solids and 111 bbl of drilling fluid would be discarded; or a total of 171 bbl would be required to keep the pit levels constant.

The remaining solids would need to be diluted with clean drilling fluid.

Drilled solids = (0.08)(dilution volume)

Dilution volume = 40 bbl/0.08 = 500 bbl

The dilution volume would consist of 40 bbl of drilled solids and 460 bbl of clean drilling fluid. Since 111 bbl would be required to keep the pit volumes constant, an additional 349 bbl would be needed to dilute the remaining drilled solids to the targeted value of 8% vol. Only a volume of 111 bbl is available after the solids removal equipment has discarded the 70% volume of solids arriving at the surface and the liquid associated with the cuttings. The actual discard would be the 111 bbl from the equipment and an additional 349 bbl to allow the remaining drilled solids to be diluted to the targeted value of 8% vol. This means that the ratio of actual volume of discard to the volume drilled would be (171 bbl + 349 bbl)/100 bbl or 5.0.

12.15.6 Optimum solid removal efficiency

The information just calculated for the five different equipment solids removal efficiencies indicates that the volume of discard rises rapidly after it reaches a minimum value. In this case, with 35% volume of drilled solids in the discards and a targeted drilled solids concentration of 8% volume, the optimum solids removal efficiency is around an 80% removal efficiency.

As the permitted drilled solids concentration is allowed to increase, the volume of dilution fluid decreases. For the targeted drilled solids concentration of 8% volume, the optimum drilled solids removal efficiency is 80%. The volume of clean drilling fluid needed to dilute the remaining drilled solids in the drilling fluid is exactly the volume of discards from the equipment. Solids removal efficiencies below 80% require a significant larger volume of dilution to keep the drilled solids concentration (DSC) at the targeted value of 8% vol.

This optimum value of removal efficiency for various targeted drilled solids concentrations and drilled solids concentration in the discarded slurry can be calculated from the equation:

$$\text{Optimum Solids Removal Efficiency} = \frac{(1 - \text{Target DSC in drilling fluid})}{1 - \text{Target DSC in drilling fluid} + (\text{Target DSC}) / (\text{DSC in discard})}$$

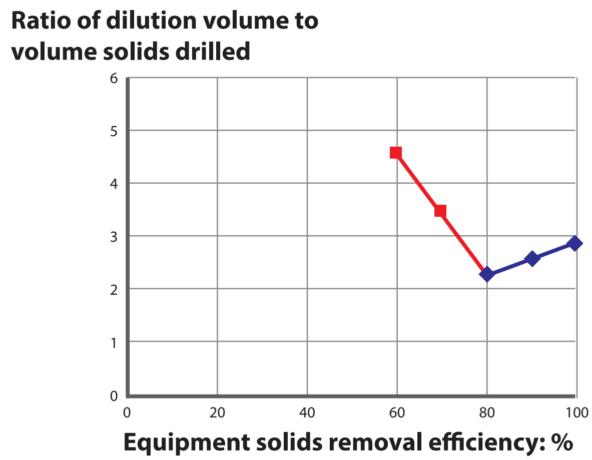


Figure 12-41: Calculations for five different solids-removal efficiencies indicate that discard volume increases rapidly after reaching a minimum value.

This equation is derived in Appendix 12C.

Assume the drilled solids concentration in the discard is 35% volume and the target drilled solids concentration is 8% volume.

$$\text{Optimum Solids Removal Efficiency} = \frac{(1 - 0.08)}{1 - 0.08 + (0.08/0.35)} = 0.80$$

If the same analysis is performed for other solids removal efficiencies and other values of targeted drilled solids concentrations, a series of curves reveals how rapidly the dilution volumes increase with poor removal efficiencies. As the requirement for a clean drilling fluid decreases (i.e., going from a 4% volume drilling fluid to a 12% volume drilling fluid), the volume of dilution decreases markedly. This, however, simply means that the drilling fluid cost will decrease while the well costs rise rapidly.

Figure 12-42 shows the effect of the solids concentration in the discards from the drilling fluid system and the effect of the targeted drilled solids concentration on the volume of clean drilling fluid needed.

The minimum volume required to dilute solids remaining after processing the solids control equipment depends upon the drilled solids concentration in the drilling fluid. If all of the drilled solids are removed from the system, the clean drilling fluid added to return the pit levels back to the original level will dilute the solids already in the drilling fluid. As noted earlier, more clean drilling fluid will be needed to return the pits to the original level with 100% removal than 90% removal of drilled solids. The smallest volume required will occur when the system is "balanced", i.e., no excess drilling fluid is needed to dilute the drilled solids returning to

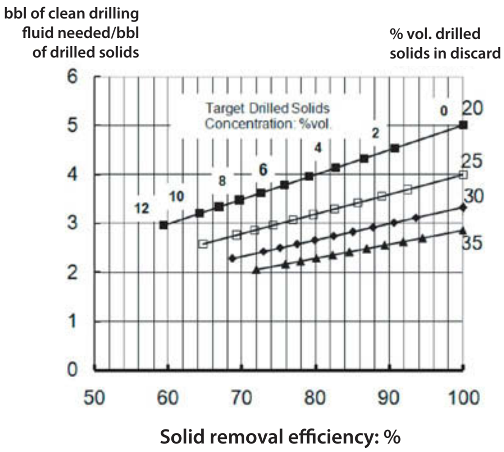


Figure 12-42: Minimum possible dilution volume.

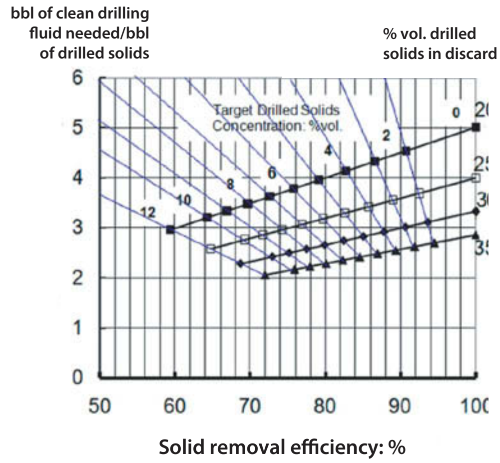


Figure 12-43: Effect of targeted drilled solids concentration and percent in discard.

the system. The same solids removal efficiency that provides the minimum quantity of new drilling fluid to be built will also be the removal efficiency that generates the minimum discard volume. This would a condition where the volume of clean drilling fluid required to dilute the solids remaining after processing through the removal equipment is exactly the volume discarded by the equipment.

$$\text{Optimum Solids Removal Efficiency} = \frac{(1 - \text{Target DSC in drilling fluid})}{1 - \text{Target DSC in drilling fluid} + (\text{Target DSC}) / (\text{DSC in discard})}$$

The derivation for this equation is presented in the Appendix. For the case above where the targeted drilled solids concentration is 4% volume, and the drilled solids concentration in the discard is 35% volume, the optimum solids removal efficiency would be:

$$\text{Optimum Solids Removal Efficiency} = \frac{(1 - 0.04)}{1 - 0.04 + (0.35/0.04)} = 89.4\%$$

If the solids removal efficiency is lower than the optimum, the amount of dilution required increases rapidly. Figure 12-43 shows the effect of lower than optimum efficiencies on the attempts to keep drilled solids under control in a drilling fluid. As the targeted value decreases, the requirement for clean dilution drilling fluid decreases. Relaxed requirements are usually required where the solids control equipment is not adequate to perform the proper function of removing drilled solids. This could be caused by fluid bypassing the equipment, poor maintenance, inadequate capacity, poor plumbing, holes in the shaker screens, plugged desilter cones or a variety of other problems.

The volume of clean drilling fluid needed is smaller when smaller quantities of drilling fluid cling to the discarded drilled solids. This causes the urge to recover the liquid phase from the discarded solids. However, when the liquid phase is salvaged, undesirable colloidal solids remain with the liquid. The economics are difficult to evaluate because of the difficulty in evaluating the damage to drilling performance and to the longterm effects of poor cement jobs. The cost reduction from salvaging the liquid phase can be calculated easily for the drilling fluid; however, the consequences of this operation may cost more.

Note also that Figures 12-42 and 12-43 assume that the drilled solids concentration never changes. In actual practice, if the optimum solids removal efficiency is not achieved, the drilled solids concentration will rise slowly throughout the day. Periodically, dilution must be used to return the drilled solids concentration back to the correct value.

12.15.7 60% Example solids removal problem and solution

A 13.0-ppg fresh water drilling fluid in a 1,000-bbl system has a targeted drilled solids concentration of 4% volume. The solids removal efficiency for the equipment is only 60%. After 100 bbl of drilled solids report to the surface, how much does the drilled solids concentration change in the active system?

Several assumptions need to be made: Assume the low-gravity density is 2.6 gm/cc and the barite density is 4.2 gm/cc. Assume the average porosity of the solids is 10% volume.

Solution:

Calculate the volume of drilled solids in system before drilling:

Volume of original drilled solids = (0.04)(1,000 bbl) = 40 bbl

Calculate the volume of new hole generated:

Volume new hole = (0.10)(drilled solids volume)+(drilled solids volume)

Volume new hole = 1.1(100 bbl) = 110 bbl

Calculate volume of drilled solids and fluid discarded:

Volume of drilled solids discarded = (0.60)(100 bbl) = 60 bbl

Volume discarded = (60 bbl) / (0.35) = 171 bbl

Volume of drilling fluid discarded = 171 bbl – 60 bbl = 111 bbl

Calculate volume of new drilled solids remaining in system:

Volume original solids remaining = (0.40)(100 bbl) = 40 bbl (or 100 – 60 bbl)

Calculate volume of original drilled solids remaining in system:

Volume original solids remaining = (40 bbl) – (0.04)(111 bbl) = 36 bbl

Calculate volume of total drilled solids in system after drilling:

Volume of drilled solids = 36 bbl + 40 bbl

If the pit levels remain constant, only 110 bbl of clean fluid can be added. The total volume of the system will now be 1,110 bbl and it will contain 76 bbl of drilled solids or 6.8% volume drilled solids.

The total solids content can be calculated from the equation:

$V_{LG} = 62.5 + 2.00\ V_S - 7.50\ MW$
$6.8 = 62.5 + 2.00\ V_S - 7.50\ (13.0\ ppg)$
$V_S = 20.9\%$

The original solids content of the fluid before drilling was:

$V_{LG} = 62.5 + 2.00\ V_S - 7.50\ MW$
$6.0 = 62.5 + 2.00\ V_S - 7.50\ (13.0\ ppg)$
$V_S = 20.5\%$

This change will not be detected by mud engineers using a 20-cc retort. The increase in drilled solids occurs slowly while drilling. The effect, however, at the end of a long interval may be devastating.

12.15.8 Discarded solids

Solids discarded by the solids removal equipment contain some of the original resident drilled solids and the new drilled solids that have just entered the system. For example, in the case above for the 70% removal efficiency, 70% of the newly drilled solids are discarded in a slurry of drilling fluid. The target drilled solids concentration in the example problem above was 4% volume. For the case of 70% removal efficiency, 70 bbl of drilled solids will be discarded in a 200-bbl slurry that contains 130 bbl of drilling fluid. The 130 bbl of drilling fluid will contain 5.2 bbl of resident solids. The total quantity of drilled solids will be 75.2 bbl. The equipment solids removal efficiency only relates to solids that are removed that decrease the solids concentration in the system. If 130 bbl of drilling fluid are dumped from the system, the remaining drilling fluid still has a 4% volume of drilled solids. Whereas, the 70 bbl removed by the equipment reduces the total solids concentration in the system.

12.16 Optimum equipment solids removal equipment

Equating the volume of clean drilling fluid needed to the volume of discard results in the minimum volume of clean drilling fluid needed and, as a consequence, the minimum volume of drilling fluid disposal. For that reason the resulting solids removal efficiency required is called the optimum solids removal efficiency. It is independent of the volume of drilled solids reaching the surface, or the volume of the drilling fluid system.

Appendix 12A: Derivation of formula to determine drilled solids density

In Step 1, solids added to the mud balance cup have the same mass as the water which would fill the cup:

Volume of solids = (mass of solids)/(SG of solids)
Volume of solids = [(vol of cup)(SG of water)] / (SG of solids)

Where:
SG is specific gravity, gm/cc

After adding water to the dry solids:
Volume of water added = vol of cup – vol of solids
Volume of water added = vol of cup
– [(vol of cup)(SG of water) / (SG of solids)]
Slurry density = mass of slurry / volume of cup
Mass of slurry = mass of solids + mass of water
Mass of solids = (vol of cup)(SG of water)
Mass of water = vol of water (SG of water)
= (vol of cup – vol of solids) SG of water
Slurry density = (mass of slurry) / vol of slurry.
Slurry density
= (mass of water + mass of solids) / vol of cup.
Slurry density = [(vol of cup – vol of solids) SG of water)
+ (vol of cup)(SG of water)] / vol of cup.
Slurry density = [2SG of water (vol of cup)
– (vol of solids)] / vol of cup
Slurry density = 2 SG of water - [(vol of cup)(SG of water)] / (SG of solids)] / vol of cup
Slurry density = 2 SG of water – SG of water/ SG of solids

Solve for SG of solids and measure slurry density:

$$SG = \frac{1}{2 - MW \frac{gm}{cc}}$$

$$SG = \frac{8.34 \text{ ppg}}{16.68 \text{ ppg} - MW \text{ (ppg)}}$$

Appendix 12B: Derivation of slug effectiveness equations

The appropriate equations can be derived from considering the fact that P1 is equal to P2.

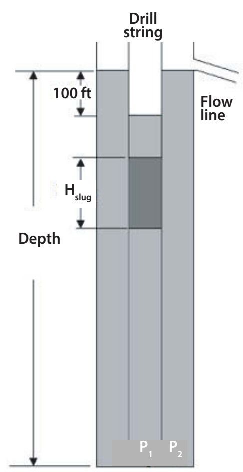
$$P_1 = P_2$$

$$0.052\,(MW_{slug})\,(H_{slug}) + 0.052\,(MW_{orig})\,(\text{Depth} - 100 - H_{slug}) = 0.052(MW_{orig})\,(\text{Depth})$$

$$(MW_{slug})\,(H_{slug}) - (100)\,(MW_{orig}) - (MW_{orig})\,(H_{slug}) = 0$$

$$MW_{slug} = \frac{MW_{orig}\,(100 + H_{slug})}{H_{slug}}$$

Where:
MW_{slug} is the mud weight of the slug, ppg
H_{slug} is the height or length of slug inside the drill string, ft
MW_{orig} is the mud weight of the drilling fluid in the hole, ppg



The liquid level in the drill string is 100 ft below the flow line. The pressure at the lower end of the drill string would be the hydrostatic head of the slug and the original drilling fluid density (P1). In the annulus, the pressure (P2) is the hydrostatic pressure from the fluid in the annulus. Obviously, these two pressures are equal.

The hydrostatic pressure at the lower end of the slug must compensate for the loss of liquid in the 100 ft of pipe above the slug and the displacement fluid.

Normally, slugs have a volume of around 20-50 bbl. Different size drillpipe will have different lengths of slugs and will require different increases in slug density to cause the liquid level in the drillstring to remain 100 ft below the flow line.

Figure 12-B1: Sketch of slug in a drill string in a wellbore.

Appendix 12C: Derivation of optimum solids removal efficiency

$$\text{Volume of discard} = \frac{\text{(SRE)(DS arriving at surface)}}{\text{DS concentration in discard}}$$

Where:

DS is drilled solids

SRE is solids removal efficiency

Volume of clean drilling fluid needed to keep DS constant:

Volume of new drilling fluid built = volume of clean drilling fluid + volume of retained drilled solids

The volume of new drilling fluid built and the volume of retained drilled solids (DS) may be expressed in terms of the discard concentration and the targeted DS concentration in the drilling fluid. Developing expressions for the two terms on the right side of the equation:

The volume of new drilling fluid built requires that the drilled solid concentration (DSC) in the new fluid be the targeted concentration, or:

DS volume = (targeted DSC) (clean drilling fluid built)

Solving this for the volume of clean drilling fluid needed:

$$\text{Volume of clean drilling fluid needed} = \frac{\text{DS volume}}{\text{Targeted DSC}}$$

The second term on the right side of the equation relates to the volume of retained drilled solids, which is determined by the solids removal efficiency (SRE):

Volume of retained drilled solids = (1 – SRE)(DS to the surface)

These expressions may now be substituted into the expression for the volume of clean drilling fluid that needs to be added to the drilling fluid system which is:

Volume of new drilling fluid built = volume of clean drilling fluid + volume of retained drilled solids

$$\text{New drilling fluid built} = \frac{\text{DS volume}}{\text{Targeted DSC}} + (1 - \text{SRE})\ \text{(DS to the surface)}$$

The minimum dilution volume is when the volume available in the active system is exactly equal to the volume of discard while keeping the drilled solids concentration constant. This means that for the minimum volume of dilution:

Volume of new drilling fluid built = volume of discard

Volume of discard = (SRE) (DS arriving at surface)

$$\frac{\text{DS volume}}{\text{Targeted DSC}} + (1 - \text{SRE})\ \text{(DS to the surface)}$$

$$= \text{(SRE) (DS arriving at surface)}$$

Solving this equation for the optimum SRE:

Optimum Solids Removal Efficiency =

$$\frac{(1 - \text{Target DSC in drilling fluid})}{1 - \text{Target DSC in drilling fluid} + \text{(Target DSC) / (DSC in discard)}}$$

Appendix 12D: Derivation of mud gun flow rate equation

The equation for flow through a mud gun in response to the head applied to the mud gun starts with the fundamental equation of the equality of energy.

Potential Energy = Kinetic Energy

Change to pressure because the correct definition of pressure is energy per unit volume.:

$$\frac{\text{Potential Energy}}{\text{Volume}} = \frac{\text{Kinetic Energy}}{\text{Volume}} = \text{Pressure}$$

$$\frac{mgh}{\text{Volume}} = \frac{\frac{1}{2}mv^2}{\text{Volume}}$$

Measurement of mass will be in terms of density (lb/gal) or weight per unit volume.

To change mass(m) to weight (W), use Newton's Second Law of Motion:

W = ma = mg

$$\frac{\frac{w}{g}gh}{\text{Volume}} = \frac{\frac{1}{2}\frac{w}{g}v^2}{\text{Volume}}$$

Weight per unit volume is called density or for drilling fluids it is called mud weight (MW)

$$MW\,(h) = \frac{1}{2}\left(\frac{MW}{g}\right)(v^2)$$

To calculate the pressure in normal units of pounds per square inch, some unit conversion must be applied. For example, the left side of the equation has the units of (lb.ft./gal) instead of lb/in^2.

To change the units (MW, lb/gal)(1gal/231 in.^{3}) [(h, ft)(12 in./ft) = 0.052 (MW, lb/gal)(h,ft)]. This should be a very familiar equation to people involved with well control.

Since this equation is to be used to calculate the flow rate (Q) through a mud gun nozzle, the velocity (v) must be changed to flow rate divided by area (A). The area will be calculated from the diameter (d) of the mud gun and will be:

$$A = \frac{\pi}{4}d^2 = 0.7854\,d^2$$

Conversion of the units on the right side of the equation:

½ (MW/g)(Q^2/(0.785 d^2))

The units in the equation must be modified to provide the pressure in pounds per square inch.

$$MW\,(h) = \frac{1}{2}\left(\frac{MW, \frac{lb}{gal}\left(\frac{gal}{231\ in.^3}\right)}{g, \frac{ft}{sec^2}\left(\frac{12\ in.}{ft}\right)}\right)\left(\frac{Q, \left(\frac{gal}{min}\right)^2\left(\frac{231\ in.}{gal}\right)^2\left(\frac{min}{60\ sec}\right)^2}{(0.785\ d^2, in.^2)^2}\right)$$

$$= \frac{MW\,(Q^2)}{7{,}429}$$

$$MW\,(h) = \frac{1}{2}\left(\frac{MW}{g}\right)(v^2)\text{, now becomes}$$

$$0.052\left(MW, \frac{lb}{gal}\right)(h, ft) = \frac{\left(MW, \frac{lb}{gal}\right)\left(Q\,\frac{gal}{min}\right)^2}{7{,}429}$$

Solving for the flow rate:

$$Q,\ gal/min = 19.6\,(d, in.)^2\,(\sqrt{h, ft})$$

Chapter 13
Drilling Fluid Properties

TABLE OF CONTENTS

13.1 INTRODUCTION

This chapter discusses drilling fluid properties necessary to drill as rapidly as possible with minimum trouble. Many textbooks are available which discuss these subjects in depth. This chapter concentrates on some of the aspects of drilling fluids that are frequently misunderstood, as well as the importance of some of the traditional measurements of drilling fluid properties. This chapter does not discuss drilling fluid selection, treatment of contaminants, or drilling fluid ingredients.

This book discusses optimization procedures required to drill wells as fast and trouble free as the rig will permit. Required drilling fluid properties have been discussed in each of the chapters. This chapter will concentrate on explaining how these properties affect rig performance and discuss the effects in depth.

A drilling fluid has many responsibilities:

- Remove cuttings from beneath the drill bit before they are reground;
- Transport cuttings to the surface with the minimum amount of regrinding;
- Prevent a blowout;
- Prevent changes in borehole diameter (maintain wellbore stability);
- Create a "slick" hole to prevent stuck pipe;
- Create a "slick" hole for extended reach or horizontal holes to reduce torque;
- Control corrosion;
- Prevent lost circulation;
- Prevent near-wellbore flushing of hydrocarbons;
- Prevent extensive skin damage;
- Cool the bit.

This chapter will concentrate on providing guidance on how to achieve all of the requirements listed above. Specifically, drilling fluid needs to have the lowest plastic viscosity possible, adequate low-shear-rate viscosity to transport cuttings, and produces a filter cake that is thin, slick and compressible.

13.2 Hydraulics

The first function of a drilling fluid in the list above is to remove cuttings as soon as they are created. This means that the impact force or the hydraulic power of the drilling fluid exiting from the bit nozzles should be the maximum value possible. This will remove the maximum number of cuttings from the bottom of the hole before they are reground by the next row of bit teeth. The maximum hydraulic power or maximum impact force can be calculated from procedures listed in Chapter 3, Hydraulics.

Another aspect of obtaining good bottomhole cleaning is requiring the lowest possible viscosity for the fluid striking the bottom of the wellbore. This viscosity can be approximated by the value of the plastic viscosity (PV) of the drilling fluid. See discussion in Appendix 13A. PV should be as low as possible. Plastic viscosity depends upon the liquid phase viscosity and the size, shape, and number of particles in the drilling fluid. Some solids must be added for filtration control; frequently solids (barite) are added to increase the fluid density, and some solids are used to increase the low-shear-rate viscosity for hole cleaning. Drilled solids, however, should not be allowed in the drilling fluid.

The yield point (YP) of the drilling fluid is usually adjusted to provide cuttings transport up the annulus. Actually, the adjustment should be described as increasing the low-shear-rate viscosity, not the YP (which is an extrapolated shear stress value).This calculation is described in Chapter 6, Carrying Capacity.

The filter cake deposited while drilling should be thin, slick, and compressible. This will not only help with eliminating stuck pipe and lost circulation, but will be essential for moving the casing while cementing. The economic consequences of a poor cement job are difficult to calculate. When hydrocarbons flow from a production zone up the hole into a barren formation, the loss of revenue can be staggering. Noise logs can be used in wells to find flow behind casing.

13.3 Simple rheological models

Rheology models attempt to describe how the shear stress changes with shear rate. Many complex models have four, five or six constants for the shear stress/shear rate relationship.

13.3.1 Newtonian fluid

The simplest is when the shear stress is directly proportional to the shear rate. This fluid is called a "Newtonian fluid" and the ratio of shear stress to shear rate would be a constant. The mathematical relationship needs only one constant to describe how shear stress (SS) changes with shear rate (SR).

SS = (constant) SR

The constant would be the viscosity of the fluid — that is the definition of viscosity. If the shear stress, in dynes/cm^2, is divided by the shear rate in reciprocal seconds, the viscosity would have the units of poise. Water at room temperature has a viscosity of one centipoise or one-hundredth poise. As long as the temperature remains constant, water has the same viscosity no matter how fast it is moving.

13.3.2 Two parameter rheological models

The next more complex rheological model is one in which two constants are needed to describe the relationship between shear stress and shear rate. The Bingham plastic model uses two constants describing a straight line, and the power law model uses two constants to describe a curved line which passes through the origin.

13.3.2.1 Bingham plastic model

The Bingham plastic mathematical model relates the shear stress to a linear relationship with the shear rate just like the Newtonian fluid model, except that a yield point is added. The equation is :

SS = (PV) SR + YP, where PV is the plastic viscosity and YP is the yield point

This is the same equation used in algebra to describe a straight line:

Y = m X + b, where m is the slope of the line and b is the y-intercept

Obviously, if the YP is zero, the fluid would be called a Newtonian fluid because then the viscosity would be constant for all shear rates.

Plastic viscosity should be as low as possible to assist the drilling fluid's removal of cuttings from beneath a drill bit. Plastic viscosity depends upon four things in the drilling fluid: liquid phase viscosity, size, shape and number of solids. This is an indicator of the drilled solids in the drilling fluid.

The solids content, as determined by the retort, can remain constant, but PV will increase as solids grind into smaller particles. The founder point of a drill bit depends upon the ability of the drilling fluid to remove cuttings from beneath the drill bit. Increasing values of PV will lower the founder point. If the founder points are not measured, failure to remove the cuttings may make the rock appear to be much harder than it really is as the drilling rate decreases.

Water-based drilling fluid viscosity is also a function of temperature; non-aqueous drilling fluid (NADF) viscosity is not only a function of temperature but also pressure. Viscosities measured at 120°F cannot be extrapolated to downhole viscosities and this makes accurate pressure loss calculations very difficult. At temperatures above about 200°F, the viscosity variation of three water-based drilling fluids show some unexpected behaviors (Figure 13-1). These variations in viscosity depend upon the ingredients in the drilling fluid and, at the present time, cannot be predicted. This makes calculation of pressure losses in the circulating system very difficult. This is the reason why the Hydraulics Chapter was written.

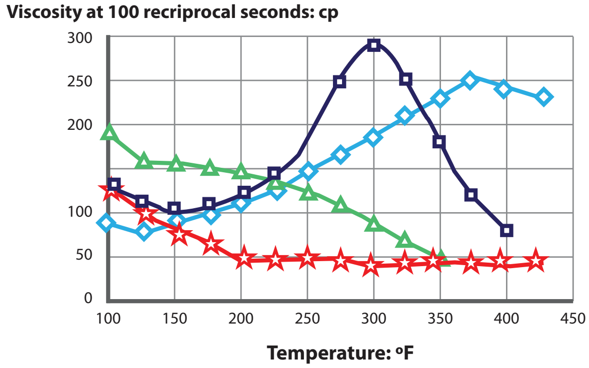


Figure 13-1: Variation in viscosity with temperature of four different water-based drilling fluids.

13.3.2.2 Power law model

The power law model describes the shear stress (SS) as proportional to the shear rate (SR) raised to some exponent (n):

$SS = K\,(SR^{\,n})$

Where "K" is the constant of proportionality.

If the equation is solved for "K" and n = 1, K would be the ratio of shear stress to shear rate, which is the definition of viscosity. That describes a Newtonian fluid.

This model comes closer to describing the lower shear rate viscosities of drilling fluid than the Bingham plastic model. This is the model used in the carrying capacity index (CCI) to help provide some guidance for bringing cuttings to the surface in holes up to 35°. (See Chapter 6.)

At 300 rpm, the shear rate is 511 reciprocal seconds, calculated from (300)(1.7). The 300 rpm Fann reading is PV+YP and this must be multiplied by the conversion factor 511:

$$K = \frac{511 R_{300}}{[1.7\ (300\ \text{rpm})]^{n}}$$

The values for "n" and "K" can be calculated from the equations below:

$$n = 3.322 \log\left(\frac{2\ PV + YP}{PV + YP}\right)$$

$$K = (511)^{1-n}\ (PV + YP)$$

The shear stress in dynes per square centimeter (dynes/cm^2) is used to compute the value of K. This converts the units to "effective viscosity". For example, if a drilling fluid has the following attributes:

R600 reading = 50
R300 reading = 35

PV = 15
YP = 20

Then:
PV + YP = 35 = R_{300}
2PV + YP = 50 = R_{600}

Calculating n:
n = 3.322 log (50/35) = 0.51

Calculating K:
K = $(511)^{1-n}$ (35) = $743_{\text{eff cp.}}$

These are the equations used to calculate the "K" value in the carrying capacity index (CCI) for hole cleaning.

13.4 Drilling fluid rheology

Drilling fluid is rheologically complex: it is a shear-thinning fluid. That means that the viscosity decreases as the shear rate increases. The viscosity also decreases as the temperature increases. Non-aqueous fluids (NAF) will also increase in viscosity as the pressure increases. These factors make it very difficult to calculate pressure losses in a pipe when the viscosity is unknown. Pressure losses also depend upon whether the fluid flow is laminar or turbulent. At each tool joint, turbulence can be created that propagates down into the next joint of pipe. The ratio of turbulence flow length to laminar flow length depends upon the drilling fluid properties at that pressure and temperature. This is the reason that computer programs have great difficulty predicting standpipe pressure before the well is drilled.

13.5 Viscosity

Viscosity is defined as the ratio of shear stress to shear rate. If the shear stress is measured in dynes/sq cm and the shear rate in sec^{-1}, the viscosity has the units of poise. The viscosity of most common fluids is reported in centipoise, or one-hundredth of a poise. For example, the viscosity of water at room temperature is about one centipoise.

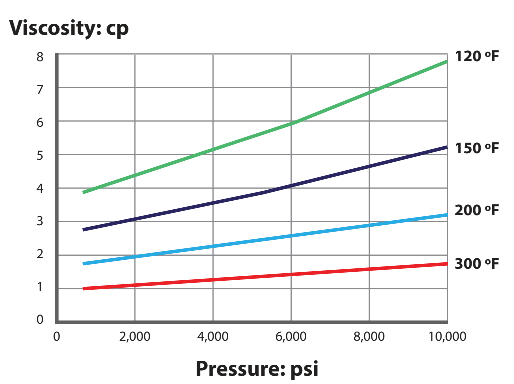


Figure 13-2: Changes in viscosity with temperature and pressure of a synthetic NAF.

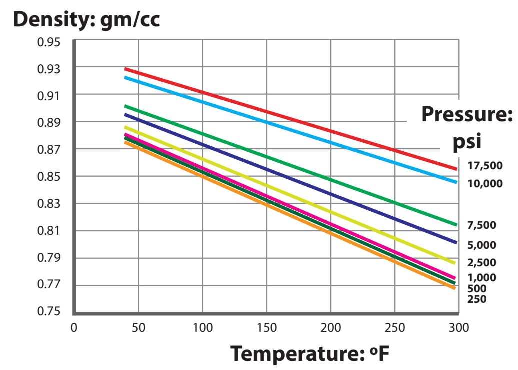


Figure 13-3: Change in density of a synthetic oil.

If the viscosity remains constant no matter what the shear rate, the fluid is said to be a Newtonian fluid. The viscosity may change with pressure and the fluid is still called a Newtonian fluid. Water viscosity changes with temperature but not pressure. Oil, however, changes viscosity with both temperature and pressure (Figure 13-2). Both are Newtonian fluids because the viscosity is independent of shear rate.

Not only does the viscosity of a synthetic NAF change with pressure and temperature, but the density also changes (Figure 13-3). This clearly indicates the problem associated with calculating pressure losses while circulating a fluid that changes viscosity throughout the circulating system.

Many fluids, however, also change viscosity with shear rate. With a drilling fluid, the viscosity of the fluid exiting from the nozzles should be as low as possible to provide the necessary velocity and force to move the cuttings from the bottom of the hole. The cuttings are brought to the surface with the drilling fluid circulating up the annulus. This viscosity should be much higher to assist in cuttings transport. These

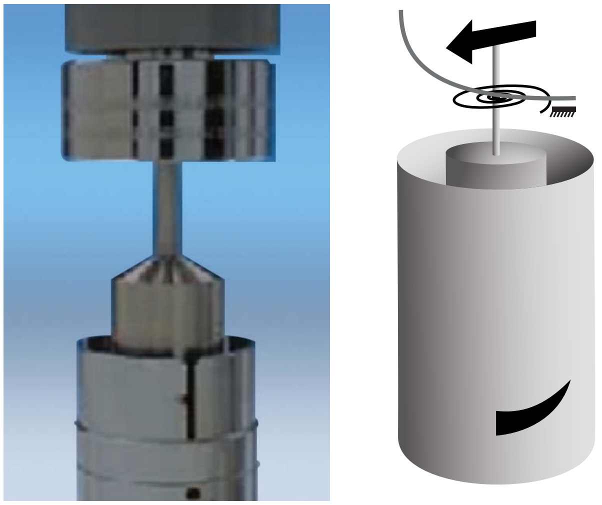


Figure 13-4: Concentric cylinder viscometer.

Table 13-1: Calculating PV and YP.	
Speed: RPM	Dial reading: lb/100 sq ft
600	85
300	55
PV	30 cp
YP	25 lb/100 sq ft

fluids have a high viscosity at low shear rates and a low viscosity at high shear rates. These are called "shear-thinning" fluids. Obviously, a Newtonian fluid would not satisfy these requirements.

The fluid passing through the nozzles has a very high velocity through a very small opening, thus there is a very high shear rate. The fluid moving up the annulus between the drill string and the hole is moving with a much lower velocity and has a much lower shear rate. The drilling fluid should, therefore, have a high viscosity when it is moving slowly and a low viscosity when it is moving fast. This is called a "shear-thinning fluid". This is what is created to drill a well.

13.5.1 Measuring viscosity

Drilling fluid flow properties are measured with a concentric cylinder viscometer (Figure 13-4). The most common viscometer has six fixed speeds for the outside cylinder. As the outer cylinder rotates, the fluid between the cylinder and the bob tends to twist the bob. The bob rotation is restrained with a spring. As the bob turns, a dial indicator measures the angle of the twist of the bob. When the spring force matches the shear stress on the bob, the bob ceases to turn. This is the dial reading used to measure the shear stress on the surface of the bob.

A standard concentric cylinder viscometer has six rotational speeds for the outer cylinder: 600 rpm, 300 rpm, 200 rpm, 100 rpm, 6 rpm and 3 rpm. This provides a series of different shear rates so that the rheology profile can be determined. Drilling fluid does not have "a viscosity". The viscosity changes with each shear rate. In a drilling fluid, the viscosity decreases as the shear rate increases.

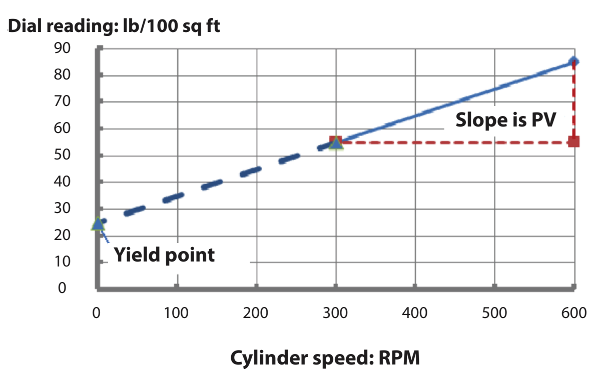


Figure 13-5: Concentric cylinder readings converted into PV and YP.

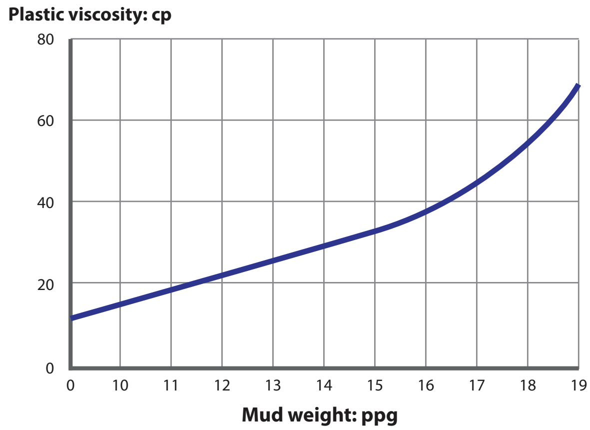


Figure 13-6: Suggested maximum values for PV in a water-based fluid.

The Bingham plastic model is a two-parameter model which relates the shear stress to the shear rate with a simple straight line equation:

Shear Stress = (PV) Shear Rate + YP

Where PV is the plastic viscosity and YP is the yield point. By convention, the 600-rpm and the 300-rpm readings are used to calculate PV and YP (Table 13-1).

These values are plotted in Figure 13-5.

Plastic viscosity should be as low as possible to assist the drilling fluid's removal of cuttings from beneath a drill bit. Plastic viscosity depends upon four things in the drilling fluid: liquid phase viscosity, size, shape and number of solids. This is an indicator of the drilled solids in the drilling fluid.

Some guidelines for the maximum value of plastic viscosity for a water-based drilling fluid are shown in Figure 13-6. As the weighting agent (barite) is added to increase the mud weight, the plastic viscosity will rise. A similar guideline for a non-aqueous drilling fluid (NADF) is difficult to describe because the liquid phase viscosity varies from one brand to another.

The solids content, as determined by the retort, can remain constant, but PV will increase as solids grind into smaller particles. The founder point of a drill bit depends upon the ability of the drilling fluid to remove cuttings from beneath the drill bit. Increasing values of PV will lower the founder point. If the founder points are not measured, failure to remove the cuttings may make the rock appear to be much harder than it really is as the drilling rate decreases. This is discussed in Chapter 4.

Table 13-2: Converting rheometer readings to viscosity.		
Reading	Speed: RPM	Viscosity: cp
85	600	42.5
55	300	55
43	200	65
36	100	108
7	6	330
4	3	400

One other word of caution seems appropriate here. The Bingham plastic model works very well for treating drilling fluid. Plastic viscosity provides an insight into the solids within the drilling fluid; yield point provides an insight into contamination and/or electrochemical interactions. The Bingham plastic model does not describe the low-shear-rate condition of the drilling fluid very well and should not be used to calculate pressure profiles and behavior.

13.5.2 How to convert viscometer readings to proper units

The commonly used viscometer on drilling rigs measures the shear stress in units of lb/100 sq ft and the shear stress in units of RPM of the outer cylinder. Multiplying the shear stress reading by a factor of 5.11 will convert the shear stress to the units of dynes/sq cm. Usually, the unit of centipoises is used for viscosity rather than the unit of poise. So the conversion factor for the shear stress becomes 511. Multiplying the shear rate RPM by the factor of 1.7 will convert it into units of reciprocal seconds. In Table 13-2, a typical set of viscometer readings has been converted into viscosities for the different rotational speeds of the cylinder.

For example, if the dial reading is 48 lb/100 sq ft at 600 rpm, the viscosity in centipoise would be:

$$\text{Viscosity} = \frac{48}{600} \times \frac{5.11 \times 100}{1.7} = \frac{48}{600} \times 300 = 24 \text{ cp}$$

The ratio of (5.11 x 100)/1.7 is a constant "300". This means that every value of dial reading on the rheometer can be converted into a viscosity for that rheometer speed or shear rate, as shown in Table 13-2.

The drilling fluid properties reported on morning reports use the simplest possible rheological model: the Bingham plastic model. Rheology is usually measured at a single temperature daily, usually 120°F. This model has only two variables, plastic viscosity and yield point (PV and YP), and allows the fluid to be evaluated in terms of solids content or electrochemical problems. The 300-rpm reading is subtracted from the 600-rpm reading to calculate the PV, the PV is subtracted from the 300-rpm reading to calculate the YP (Table 13-1).

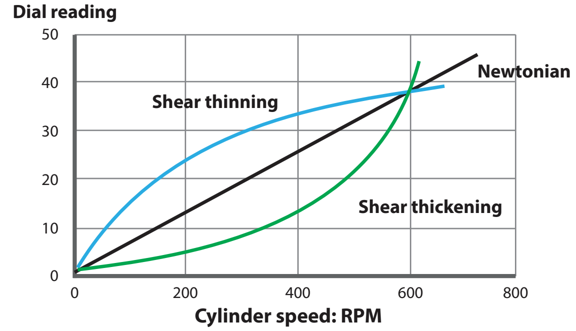


Figure 13-7: Shear stress as a function of shear rate for three different types of fluids.

13.6 Comment on rheological models

Unfortunately, many confuse rheological models with the definition of viscosity. A rheological model attempts to describe the entire shear stress vs. shear rate curve. The ratio of any point (shear stress divided by shear rate) on the curve is the viscosity of the fluid. Most frequently, a curve which represents the relationship between shear stress and shear rate for a drilling fluid is made confusing by a line from some point to the origin. A statement is then made that this would be the viscosity of a Newtonian fluid. While that is true (if there was a Newtonian fluid with those shear stress-shear rate values), it would be equally true that this value would be the viscosity of a Hershel-Buckley fluid, or a shear-thickening fluid, if the curve passes through that point. Relating a point on a shear stress-shear rate curve to a viscosity of a particular rheological model becomes very confusing. In Figure 13-7, a shear thickening fluid, a Newtonian fluid, and a shear-thinning fluid all have the same viscosity (19 cp) at 600 rpm.

Water, oil and a variety of different liquids are called Newtonian fluids because the viscosity does not change with shear rate. A drilling fluid is called a shear-thinning fluid because the viscosity decreases with shear rate. The viscosity decreases as the fluid flows faster and faster through a pipe. Cornstarch or methyl methacrylate slurries actually become more viscous as the shear rate increases. Concentrated slurries of these ingredients are difficult to pump with a centrifugal pump because of this characteristic.

One other confusing point for students interested in fluid mechanics is the fact that the concentric cylinder viscometer dial reading at 300 rpm is the viscosity of any fluid at that shear rate. It is frequently confused with "Newtonian" viscosity. To change the dial reading to the unit of dynes/sq cm, the dial reading is multiplied by 5.11. To change the RPM to reciprocal seconds, the RPM is multiplied by 1.70. This will convert any ratio to the unit "poise". The normal unit is centipoise, so consequently the 5.11 is normally multiplied by 100 to convert the value to centipoise. The ratio of 511 divided by 1.70 gives a conversion factor of 300. In other words, when a ratio

Table 13-3: Converting rheometer readings to viscosity.		
Reading	Speed: RPM	Viscosity: cp
85	600	42.5
55	300	55

of readings from a properly calibrated oilfield concentric cylinder viscometer is multiplied by 300, the ratio is the viscosity in centipoise. Obviously, the dial reading at 300 rpm will be the viscosity of ANY fluid at that shear rate. The dial reading at 600 rpm will be one-half the viscosity (in centipoise) at that shear rate (Figure 13-7).

13.7 Discussion of the "K" viscosity in the power law model

In the power law rheology model, shear stress is equal to the constant "K" times the shear rate raised to the "n" power:

$$\text{Shear Stress} = K\,(\text{Shear Rate}^n)$$

If n = 1, "K" becomes a ratio of shear stress to shear rate, which is the definition of viscosity.

If "K" is the viscosity of a Newtonian fluid in centipoise, the value of shear stress must be expressed in dynes/sq cm and shear rate in reciprocal seconds. The viscometer reading must be multiplied by 511 for this conversion and the cylinder rotation speed multiplied by 1.7. This allows the value of "K" to be expressed in "effective viscosity". The units of "K" appear in all sorts of combinations in the literature. In this text, it will be such that, if n = 1, the value of "K" will be in centipoise. Frequently, the dial reading is used for the shear stress and the RPM used for the shear rate. If n = 1, this would give the viscosity in units of lb-rpm/100 sq ft. Few people would know how to relate this viscosity value to something simple like water or oil viscosity. Many publications, including the SPE treatise on calculating the value of "K", fail to convert the dial reading to dynes/sq cm, although the RPM is converted to reciprocal seconds. A conversion factor can be used because:

$$1\ \frac{\text{lb-sec}}{100\ \text{sq ft}} = 511\ \text{cp}$$

Caution must be used when evaluating other documents and other calculations because of the failure to use units which will reduce to poise or centipoise if the exponent "n" is equal to one (Newtonian viscosity). Many publications express "K" in units of lb-sec/100 sq ft. This cannot be used in the CCI correlation described in this book.

For drilling fluids, the exponent "n" is usually less than one and is an indicator of how far removed the fluid is from being Newtonian. This model comes closer to describing the lower shear rate viscosities of drilling fluid than the Bingham plastic model. This is the model used in the carrying capacity index to help provide some guidance for bringing cuttings to the surface in holes up to 35°.

At 300 rpm, the shear rate is 511 reciprocal seconds, calculated from (300)(1.7). The 300-rpm viscometer reading, R_{300}, must be multiplied by the conversion factor 5.11 to convert it to degrees/cm^2. To convert these readings to viscosity in centipoise (cp), the equation would be:

$$\text{Viscosity} = \left(\frac{R_{300}}{300\ \text{rpm}}\right)\frac{5.11 \times 100}{1.7}$$

$$= \left(\frac{R_{300}}{300\ \text{rpm}}\right)300 = R_{300},\ \text{cp}$$

In Table 13-3, the viscometer readings were converted into the proper viscosities indicated by the dial reading. The plastic viscosity, PV, can be calculated by subtracting the 300-rpm reading from the 600-rpm reading (85–55 = 30 cp). The yield point, YP, can be calculated by subtracting PV from the 300 rpm reading (55–30 = 25 lb/100 sq ft).

The power law constants ("K" and "n") can also be calculated from that data:

$$n = 3.322 \log\left(\frac{2PV+YP}{PV+YP}\right)$$

$$K = \frac{SS}{(SR)^n}$$

$$K = \frac{(511)\,R_{300}}{(RPM \times 1.7)^n} = \frac{511\,(R_{300})}{(300 \times 1.7)^n}$$

$$K = (511)^{1-n}\,R_{300}$$

$$n = 3.322 \log \frac{85}{55} = 0.63$$

This is the "K" value used in Chapter 6, which discusses the carrying capacity of drilling fluid.

13.8 High-angle wells

In a high-angle well, solids need to fall only a few inches to reach the bottom. In vertical wells, the settling distance is many feet. With the simpler drilling fluid systems of many years ago, most drilling contractors subscribed to the concept that fluid velocity was the primary parameter that would prevent settling in pipes. For example, in the backflow lines between mud tanks, barite would settle if the velocity was less than 5 ft/sec. They tried to prevent the velocity from exceeding 10 ft/sec to prevent turbulent flow.

The wisdom of that era was that velocity was the primary condition for transporting drilled solids. Fortunately, several thousand feet of horizontal hole can be cleaned with pipe rotation and high flow rates. High flow rates (turbulent flow) are responsible for breaking large cuttings into many small pieces, which increases PV and the colloidal content of the drilling fluid. Cuttings tend to arrive at the surface as small granular pieces. Attempts have been made to increase the low-low-shear-rate viscosity to aid cuttings transport. This approach does not appear to prevent solids from settling in long horizontal holes. An appreciable amount of rig time is spent back-reaming to move the cuttings up the hole. These techniques are still evolving.

Some interesting work is currently underway regarding the viscoelastic behavior of drilling fluids. The difference between a liquid and a solid seem rather clear from a superficial examination; consider, however, a salt dome. The salt is flowing upward from a deep layer and, frequently, even pushes the surface upward above the surrounding terrain. A salt core seems very solid; yet it is flowing. This is a viscoelastic behavior. Obviously, the flow is very slow; consequently, the "viscosity" would be very high.

Many complex mixtures are described mathematically by relating the shear stress to the shear rate. These are the normal methods of describing the flow of a fluid. The mixture is said to be a Newtonian fluid if the shear stress is proportional to the shear rate. The constant of proportionality is called "viscosity". An elastic solid has a shear displacement directly proportional to the shear stress. Hooke's law describes these solids by stating that the strain is proportional to the stress.

Some materials, like salt, exhibit characteristics of both liquids and solids. If such a material is subjected to an oscillatory stress, the measured strain will not exactly be in-phase with the applied stress (like an elastic solid) or exactly out-of-phase with the applied stress (like a liquid). The measured strain would be some intermediate angle between zero and ninety degrees. So the material acts like a viscous material for part of the cycle and an elastic material for part of the cycle, creating the term "viscoelastic".

The rheological equation which describes this behavior involves relating the shear stress, (τ), to a complex shear relaxation modulus, (G). The stress on the material under oscillation with a frequency of $\omega/2$) with a maximum amplitude of shear rate (γ), could be represented with the equation:

$$\tau = \gamma\,(G' \sin \omega t + G'' \cos \omega t)$$

Where:

t is time

G′ is the shear, or elastic, modulus (the in-phase component)

G″ is the viscous modulus (the out-of-phase component)

Some preliminary work has indicated that drilling fluids with a high elastic modulus have been successful in cleaning horizontal holes. The application of this technology was difficult initially because the equipment used (a cone-and-plate viscometer) was very large and not suitable for deployment into field operations. Recently, commercial instruments have become available to make these measurements at the drilling rig. The concentric cylinder viscometer has been modified to make both the normal rheology measurements (PV, YP, gels, etc.) and the viscoelastic moduli. Guidelines are not available yet to indicate the values of the elastic modulus which are needed to clean horizontal holes.

Horizontal holes can be cleaned effectively if drilled solids are prevented from falling through the drilling fluid. If a fluid does not have a reasonably large elastic modulus, solids will settle. For example, solids suspended in honey will slowly fall through the fluid; solids suspended in jelly will not fall. Why? Honey is a Newtonian fluid with a zero elastic modulus. Jelly has a very high elastic component and will suspend solids. The question has always been: "How do you produce a fluid that flows easily, but has a very high, easily broken gel structure when flow ceases?" Two common ways have been developed: high concentrations of XC polymer and MMH (or MMO).

The development of the concept of critical polymer concentrations (CPC) has been effective in cleaning very high-angle holes. XC polymer has been used for many years because of the shear-thinning characteristic and has been used effectively to clean vertical wells. Powell, Parks and Seheult, in 1991, reported increasing the concentration above 1.75 or 2 lb/bbl of XC to a CPC increased the G′ (or the elastic modulus). They reported the benefits of high concentrations of XC in drilling fluids compared with conventional fluids to be:

- Pump pressures were lower for the same flow rates;
- Circulation lag time was reduced;
- Torque and drag were reduced due to improved hole cleaning;
- Fewer problems running logging tools, casing, or liners.

Another development was the use of mixed metal hydroxides (MMH) fluid. MMH is a highly positively charged man-made additive that creates some unusual fluid properties. A MMH drilling fluid in an East Texas well had a funnel viscosity of 45 seconds, yet it would support a 2-in. diameter rock on the surface of the fluid in a mud cup. The turnkey contractor claimed they were sinking record wells in the field because

Figure 13-8: Filter cake formed from a clean NADF with 900 psi.

Figure 13-9: NADF filter cake in a "well-used" drilling fluid.

of better hole cleaning. The toolpusher on location sounded like a mud product salesman when discussing the benefits of cleaning the hole. The same gel structure created with bentonite would have required great pressure to break circulation. The additive is very sensitive to treatment on the surface and requires a very competent mud engineer to effectively use the product.

The point is that the viscous models are not working to help predict the properties needed to clean horizontal holes. The trend is to go to lower and lower shear rates to better describe solids moving slowly through the media. This does not seem to be the total solution.

13.9 Filtration

Surprisingly perhaps, the filter cake thickness does not always correlate with the fluid loss. In a water-base drilling fluid, drilled solids may decrease the fluid loss but increase the cake thickness. In a gel/lignosulfonate slurry, the fluid loss was reduced to 9.7 cc/30 min. The addition of dirt to this slurry reduced the fluid loss to 7.8 cc/30 min, but the filter cake was four times as thick as the original slurry.

Non-aqueous drilling fluids (NADF) reportedly can tolerate drilled solids. This statement is based on the fact that the drilled solids do not appreciably change the low-shear-rate viscosity of NADF. Unfortunately, this statement does not apply to filter cake quality. When the same NADF is used in a series of wells, the colloidal solids increase. As drilled solids become more and more dispersed, the surface area of the solids increases rapidly. All of these surfaces must be wetted with NAF. This leaves little free liquid. Eventually, so much liquid is associated with the solids that no liquid will leave a drop of the NADF when it is placed on a paper towel or a piece of filter paper. Tests have shown that the fluid loss with 900 psi applied is about the same as with 100 psi. The filter cake, however, becomes very, very thick. This cake cannot be removed with cement and will seriously endanger the integrity of the cement barrier during the life of the well.

When the NADF is first placed in a borehole, the filter cake is usually very thin and slick (Figure 13-8). The torque and drag on the drill string will be the lowest possible.

After the NADF has been used in several wells and the liquid phase is retained in the drilling fluid processing system, the colloidal solids increase. The normal drilled solids removal equipment currently used does not, and cannot, separate these small drilled solids from the drilling fluid. As the quantity of extremely small particles increases, the surface area which must be wetted with the liquid phase increases. This leaves little free liquid to flow from a filter cake but the solids continue to deposit on the filter media. This results in a very thick filter cake (Figure 13-9).

Appendix 13A: Plastic Viscosity

To understand what the value of PV means, the Bingham Plastic Model could be inserted into the definition of viscosity:

As the shear rate increases the ratio of YP/SR becomes smaller and smaller. At an infinite shear rate the viscosity would be the plastic viscosity. Or stating this in another way, PV is the viscosity of a drilling fluid at a very high shear rate — such as is achieved in the nozzles.

$$\text{Viscosity} = \frac{\text{Shear Stress}}{\text{Shear Rate}}$$

$$\text{Viscosity} = \frac{(\text{PV})\ \text{SR} + \text{YP}}{\text{SR}}$$

$$\text{Viscosity} = \text{PV} + \frac{\text{YP}}{\text{SR}}$$

As SR increases, the value of the ratio YP/SR decreases. When SR is infinite, the ratio of YP/SR goes to zero. Conceptually, this means that the plastic viscosity is the viscosity the fluid would have at an infinite shear rate. The flow through a drill bit nozzle has a very high shear rate. The plastic viscosity should be as low as possible to allow the fluid to remove cuttings from the bottom of the hole. The founder point of a bit depends upon the PV.

Chapter 14
Drilling Suggestions and Thoughts

TABLE OF CONTENTS

14.1 INTRODUCTION

This book seeks to help drillers drill more efficiently and safely. Some specific practical suggestions have been developed during many years of drilling experiences. This chapter is a depository for many of the more significant recommendations which have been observed and tried during many years of operation experience. Many of the same concepts are listed in API Recommended Practice 13C.

14.2 Centrifugal pumps

Centrifugal pumps seem simple but are frequently misused by rig personnel because they are not understood. Take the quiz below and determine whether you understand centrifugal pumps.

In Figure 14-1, a centrifugal pump takes suction from a tank and is connected to two joints of 4 ½-in. casing standing vertically by a rig. The top is open. Water in the tank rises 40 ft above the level in the tank and stops.

See Figure 14-2. The water is drained from the tank and replaced with a 16.6-ppg drilling fluid. This is twice the density of water. The pump is turned on. How high will the 16.6-ppg drilling fluid rise in the casing before it stops?

CHOOSE AN ANSWER:

The heavy drilling fluid will rise:

A. Higher than the water did;
B. The same height as the water did;
C. Not as high as the water did.

The answer is in Appendix 14A.

14.2.1 Suggestions for centrifugal pumps

In the removal section of the active drilling fluid system, the degasser, the banks of desanders, and the banks of desilters should all have their own pumps. One pump, one switch and one function.

The desander and desilters pumps should have only one suction and one discharge pipe. No other options should be plumbed into the centrifugal pumps.

If pumps are needed for transfer of liquids when the rig is not drilling, other pumps should be used. Complicated or multiple valves in the manifolds tend to lead to incorrect routing of the drilling fluid.

If a valve is installed on the discharge side of a centrifugal pump and a pressure gauge installed between the valve and the pump, the no-flow head (or pressure) can be determined as a diagnostic tool. The no-flow head should be the same value as the pump curves indicate. If it is, then the pump is operating correctly and the impellers do not need to be

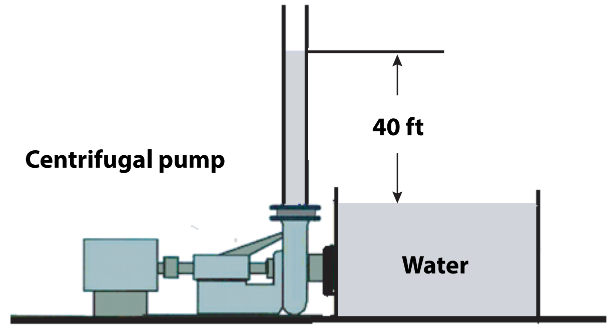


Figure 14-1: A centrifugal pump takes suction from a tank and is connected to two joints of 4 ½-in. casing standing vertically by a rig. The top is open. Water in the tank rises 40 ft above the level in the tank and stops.

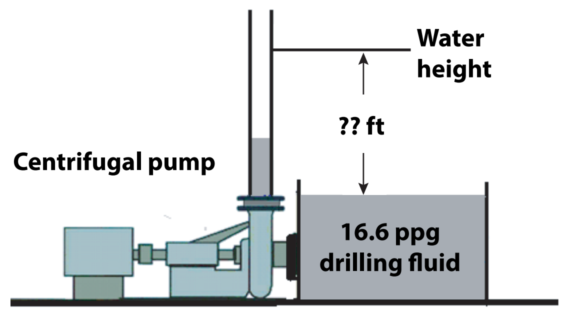


Figure 14-2: The water is drained from the tank and replaced with a 16.6-ppg drilling fluid. This is twice the density of water. The pump is turned on. How high will the 16.6-ppg drilling fluid rise in the casing before it stops?

inspected. (Word of caution: the valve can be closed for a short time without damage to the pump. Have a rule that the hand that closes the valve cannot let go of the valve handle until the valve is opened again.)

A suction valve should never be partially closed to regulate the discharge head from a pump. Starving the pump will result in cavitation which quickly destroys the impeller and sounds like the fluid contains gravel or rocks as it flows through the pump.

A long empty line attached to the centrifugal pump discharge should be slowly filled. A valve on the pump discharge should be used to hold a back pressure until the line is full. If a centrifugal pump tries to build the proper head before the line is full, too much power will be required and usually a circuit breaker will blow (or the pump motor will burn up).

Try to have a flooded suction wherever possible for centrifugal pumps. If the fluid must be lifted to the pump, a foot valve should be installed in the suction pipe.

14.3 Drilling fluid

14.3.1 In and out measurements

Drilling fluid properties should be measured on the drilling fluid in the suction tank and then on that same fluid when it exits the wellbore. The purpose of an "in-and-out" measurement is to determine how the fluid has behaved in the well and what changes have been made in the properties by circulating down the drill string and back to the surface. In some wellbores the temperature may degrade some of the drilling fluid additives. Frequently, contaminants from the formations affect the drilling fluid properties. The sample time for the "out" sample needs to be lagged so that the same fluid is measured for the in and out properties.

14.3.2 Sampling location

The "out" sample should be taken as soon as the fluid arrives at the surface. This means the sample should be taken from the back tank of the first set of shakers processing fluid from the flow line. Sometimes larger pieces of formation are contained in this sample, and they can be removed by screening through the screen in the funnel. Examine these cuttings. They should have sharp edges indicating that the carrying capacity of the fluid is adequate to transport cuttings to the surface without degradation.

The fine screens on shakers can remove some of the various additives in a drilling fluid and this will not be observed if the "out" sample is collected under the screen. On one well, a significant amount of lime was deposited in the shaker discard. This led to the conclusion that there was a large influx of acid gas, which caused significant downtime to solve this perplexing problem.

14.3.3 pH changes with temperature

The negative logarithm of the hydrogen ion concentration is called pH. The neutral point on a pH scale is the point at which there are as many hydrogen atoms as hydroxyl molecules. Normally at room temperature this occurs at a pH of 7. As the temperature increases, however, the neutral point also decreases. Table 14.1 shows how the pH of different fluids changes as temperature increases. A fluid could have a pH of 8.6 at 80°F, but the pH at room temperature (70°F) would be 10.0.

Table 14-1: Effect of temperature on pH for various fluids.

Temperature °C	Temperature °F	pH					
24	70	9.50	10.0	10.50	11.00	11.50	12.00
30	86	9.33	9.83	10.33	10.83	11.33	11.83
35	95	9.18	9.68	10.18	10.68	11.18	11.68
40	104	9.03	9.53	10.03	10.53	11.03	11.53
45	113	8.90	9.40	9.90	10.40	10.90	11.40
50	122	8.76	9.26	9.76	10.26	10.76	11.26
55	131	8.64	9.14	9.64	10.14	10.64	11.14
60	140	8.52	9.02	9.52	10.02	10.52	11.07
65	149	8.40	8.90	9.40	9.90	10.40	10.90
70	158	8.30	8.80	9.30	9.80	10.30	10.80
75	167	8.20	8.70	9.20	9.70	10.20	10.70
80	176	8.11	8.61	9.11	9.61	10.11	10.61
85	185	8.02	8.52	9.02	9.52	10.02	10.52
90	194	7.95	8.45	8.95	9.45	9.95	10.45

This effect frequently comes as a surprise to many mud engineers. It is particularly important when drilling with aluminum drillpipe. The depth capability of a rig can be extended by using aluminum drillpipe instead of steel. When drilling rigs become scarce, this is a common ploy to drill some deep holes with available drilling rigs. Generally, the mud engineer is warned about raising the pH of the drilling fluid above 9.0 or 9.5. Caustic is as detrimental to aluminum as acid is to steel. With so much pressure and serious admonitions about taking care of the pH, a diligent mud engineer may take the pH meter to the flow line to obtain an "accurate" value. The temperature adjustment on the pH meter does not account for the change in neutral point of the hydrogen/hydroxyl ions. A string of aluminum drillpipe can be lost quickly because of this effect.

14.3.4 Fluid density and viscosity

The density and viscosity of water, oil and synthetic oil are functions of temperature. The changes in these properties for non-aqueous fluids (NAF) depend upon the molecular structure of these fluids and will vary significantly with temperature and pressure. The density and viscosity of water

Table 14-2: Properties of water.

Temp. °C	Temp. °F	Density ppg	Viscosity cp
0	32	8.344	1.7870
5	41	8.345	1.5190
10	50	8.343	1.3070
15	55	8.338	1.1390
20	68	8.331	1.0020
25	77	8.321	0.8904
30	86	8.309	0.7975
35	95	8.296	0.7194
40	104	8.281	0.6529
45	113	8.264	0.5960
50	122	8.246	0.5468
55	131	8.226	0.5040
60	140	8.205	0.4665
65	149	8.183	0.4335
70	158	8.160	0.4042
75	167	8.136	0.3781
80	176	8.110	0.3540
85	185	8.084	0.3337
90	194	8.056	0.3147
95	203	8.027	0.2975
100	212	7.998	0.2818

Table 14-3: Density of water.			
°C	Density kg/cu m	°F	Density ppg
10	999.6996	50.00	8.342896
12	999.4974	53.60	8.341208
14	999.2444	57.20	8.339097
16	999.9430	60.80	8.344927
18	998.5956	64.40	8.333683
20	998.2041	68.00	8.330415
22	997.7705	71.60	8.326797
24	997.2965	75.20	8.322841
26	996.7837	78.80	8.318562
28	996.2335	82.40	8.313970
30	995.6473	86.00	8.309078
32	995.0262	89.60	8.303895
34	994.3715	93.20	8.298431
36	993.6842	96.80	8.292695
40	992.2158	104.00	8.280441
44	990.6280	111.20	8.267190
46	989.7914	114.80	8.260208

does not vary significantly with pressure, but it changes in a very predictable manner with temperature.

14.3.5 Drilling fluid suggestions

Compare the filter cake from filtration tests at room temperature with the standard API 100-psi test and a 900-psi differential test using a high temperature/high pressure (HTHP) cell. Filter cake thickness depends upon the type of solids in the fluid.

A drilling fluid with very low concentrations of drilled solids (1%-2% vol) decreases the chance of stuck pipe and lost circulation.

The API fluid loss does not correlate with the cake thickness. Fluid loss can decrease with an increase in drilled solids.

In water, the pH is a function of temperature. At 75°F, the concentration of hydroxyl ions and hydrogen ions is equal at a pH of 7.

Entrained gas or air in a drilling fluid can decrease the rig pump efficiency. In one case where the pump efficiency was measured, only 6% vol of air reduced the pump efficiency to 85%.

Measure the true mud weight with a pressurized mud balance. If one is not available, add some defoamer to a mud cup full of drilling fluid. Pour through a funnel viscometer two or three times. Measure the mud weight with a rig mud balance. The mud weight will be close to the pressurized mud balance reading.

Barite plugs are used to stop underground blowouts. Settled barite looks like an impermeable mass. It is not. Settled barite still has porosity and permeability. Many tests have shown that a settled barite plug will eventually fail. Non-settling barite plugs with good filtration control should be used to stop underground blowouts.

Water-based drilling fluids should have a calcium concentration of 100-300 ppm if bentonite is used in the fluid. Values lower than 50 ppm usually mean that there is no free calcium in the system.

Bentonite should be prehydrated for a minimum of 12 hours (preferably 24 hours) before being added to a drilling fluid. The prehydration tank should contain only water and bentonite. Do not add caustic or lignosulfonate to a prehydration tank.

Lignosulfonate deflocculates bentonite and does not disperse the clay. It actually prevents clay from dispersing.

Any drilling fluid added to an active system should be filtered through the shale shaker screens. Fluid from trip tanks or fluid from reserve pits should be added through the shale shakers.

If the sand content is larger than a trace in the suction tank, either the solids removal equipment is not functioning correctly or barite has just been added to the system. After one complete circulation after adding fresh barite, the sand content should be a trace or lower.

In drilling fluid reports, "sand" designates a particle size, not a material containing quartz.

H_2S measured with the Garrett Gas Train can be removed from a drilling fluid by adding one lb/bbl of zinc carbonate for every 500 ppm sulfide.

Densities of NADF should be measured at the same temperature daily and that temperature should be reported. Every 10°F change in temperature will result in changes of as much as 0.07 ppg.

Annular velocity does not cause hole erosion.

14.4 Drilling fluid processing

Poor tank arrangements and incorrect plumbing are frequently the cause of the failure to remove drilled solids from drilling fluid.

All compartments, except the sand trap (if used), should be agitated.

All compartments should have a TOR (Turn Over Rate) of at

Table 14-4: Flow from four 60° canted blade impellers.		
	57.5 rpm: (60 Hz)	48 rpm: (50 Hz)
Blade Diameter: in.	Flowrate: gpm	Flowrate: gpm
20	909	760
24	1,645	1,373
28	2,468	2,060
32	3,764	3,142
36	5,402	4,510
40	7,284	6,081
44	9,928	8,288
48	12,512	10,445

Table 14-5: Flow from four flat blade impellers.		
	57.5 rpm: (60 Hz)	48 rpm: (50 Hz)
Blade Diameter: in.	Flowrate: gpm	Flowrate: gpm
20	1,051	877
24	1,941	1,622
28	2,839	2,370
32	4,365	3,628
36	6,273	5,237
40	8,411	7,023
44	11,300	9,435
48	14,401	12,024

least 30 seconds. TOR is calculated by dividing the mud tank volume by the pumping rate of the agitator impellers.

Impeller pumping rates are listed in Tables 14-4 and 14-5.

The suction and additions tanks should contain a sufficient volume of treated drilling fluid to make certain that all of the fluid in the drillpipe has the same mud weight. This is needed in case of a kick.

If the main shaker(s) can process all of the flow from the wellbore through API 140 or finer screens, desanders are not needed to reduce the solids loading in desilters banks.

All mud systems (from small truck mounted rigs to the largest rig) should have three distinct separate sections: removal, addition, and suction. The size of these sections could be very small or extremely large depending upon the quantity of drilling fluid needed for the well.

The removal section should be arranged so that the fluid is processed in sequential steps.

Each piece of equipment in the removal section should discharge fluid into a compartment downstream.

Mud guns can be used in the addition and suction sections. The flow rate through a mud gun can be calculated from the equation:

$$Q\text{, gpm} = 19.6\ (\text{head in ft})^{0.5}\ (\text{diameter in in.})^2$$

Mud guns may be used in the removal section only if each centrifugal pump stirs its own suction compartment. Do not bring fluid from another compartment back into the removal section.

When centrifuging NADF, store the light slurry (overflow) in a reserve tank to be used as a completion fluid or packer fluid. (Double centrifuging NADF will retain the colloidal particles and destroy filter cake quality.)

The light slurry (overflow) from a centrifuge also makes a great gravel packing fluid. The solids will be smaller than the gravel-pack screen and the liquid phase will not change. Changing the fluid phase of a NADF frequently causes problems with wellbore stability.

14.5 Solids control

Linear motion and balanced elliptical motion shakers place screens on an upward incline. The liquid pool provides a head which assists fine screens in separating more solids. However, if the slope of the screen is too high, solids can be degraded in the pool before they can bounce their way out of the liquid. The screen can be tilted to a large angle during bottoms-up to keep from losing thick drilling fluid off the end of the shaker. However, after bottoms-up, the shaker screens should be lowered to a more reasonable elevation. Keeping the screen elevated may allow a finer screen to be mounted on the shaker. However, cuttings may be pummeled into smaller solids and pass through the screen; thus increasing the drilled solids content of the drilling fluid.

14.5.1 Solids problem without an increase in solids content

Plot the plastic viscosity daily or more frequently, like every 4-8 hours. If solids are grinding into colloidal sizes, the PV will gradually increase. The total percent of solids may not increase appreciably but if they break apart, the total number increases significantly. PV depends upon the liquid phase viscosity, the size, shape, and NUMBER of particles. These solids could be ground in the annulus on the way out of the hole. These solids could have bypassed the solids removal equipment and recirculated down hole. These solids could increase because of an undetected hole in the shaker screen. These solids could increase because the desilters cones are plugged.

14.5.2 Suggestions and thoughts

Hydrocyclones frequently have plugged orifices because of large solids. This indicates that some solids have bypassed the shaker screens.

Plugged hydrocyclones will greatly decrease the drilled solids removal efficiency.

Before a trip for a new bit, the back-tank (or possum belly) of the shale shakers should NOT be dumped into the active system or the sand trap. The large solids do not settle and will plug desilter underflows.

Even though the main shakers are processing fluid through API 170 or API 200 screens, a mud cleaner will still remove a significant quantity of drilled solids. It makes a good "insurance" package.

Most hydrocyclones need 75 ft of head for proper operation in an unweighted drilling fluid.

The hydrocyclones on a mud cleaner that are processing a weighted drilling fluid can operate properly with a lower head than 75 ft. The underflow will contain more liquid but the liquid will be filtered through the screen.

The head can be calculated from the measured pressure at the manifold from the equation:

Pressure, psi = 0.052 (mud weight, ppg) (head, ft)

If the underflow from hydrocyclones is too dry and the screen cannot properly separate the solids, a small stream of drilling fluid can be sprayed on the screen to assist the separation. Frequently, a small hose and valve can be mounted on the hydrocyclone manifold to provide the spray. The liquid phase of the drilling fluid (water or NAF) is not recommended because it causes too much dilution.

There is no commercial solids removal equipment available to use in the active system which will separate barite from drilled solids .

A centrifuge is used to eliminate drilled solids to control PV and filter cake quality.

In a weighted drilling fluid, centrifuges can remove solids smaller than about five microns. These solids could be drilled solids, barite, filtration control additives, or rheology modifiers.

When centrifuging a weighted drilling fluid, filtration additives and the rheology modifiers should be replaced to keep the drilling fluid properties required according to the program.

In an unweighted drilling fluid, centrifuges can remove most of the solids larger than about 10 microns.

A centrifuge does NOT RECOVER BARITE. It is used to control colloidal particles in a weighted drilling fluid. These particles increase plastic viscosity and destroy filter cake quality.

Both the light (overflow) slurry and the heavy (underflow) slurry from a centrifuge will contain drilled solids and barite.

14.6 Hole erosion

Frequently, in technical meetings, a comment is made stating with great certainty that high annular velocities erode wellbores. As proof, a wellbore diameter was not as large after the annular flow rate was decreased. Tests conducted in a field with IADC bits 537 indicate that other factors than annular velocity erodes the wellbore.

When the flow rate is decreased by 10%, the nozzle flow rate decreases by 10%. The hydraulic impact force decreases by 20% because hydraulic impact force is calculated by multiplying the density times the nozzle velocity times the flow rate. The hydraulic power is decreased by 30% because it is calculated by multiplying the force times the velocity. The hydraulic force will always change by twice the change in flow rate. The hydraulic power will always change by three times the change in flow rate. The guideline suggested in the SPE paper #30497 to decrease hydraulic hole erosion was to keep the nozzle shear rate below 100,000 sec^{-1}, or the nozzle impact force below 2,000 Newtons, or the hydraulic power below 200 Kw.

14.7 Random thoughts

At any gathering of people in the drilling industry, many tales are told during breaks. Some might be worth capturing.

New processes and equipment are difficult to introduce to the drillers working on rigs. George Stonewell Orsmby was involved with introducing hydrocyclones to a skeptical audience. He told about one of the first deployments of desilters on a drilling rig close to Houston, Texas, in the 1940s. The rig crew would not allow him to install the bank of desilters on their mud pits but made him install it on the berm of their reserve pit. (In those days, a large pit was dug close to the mud tanks and all excess fluids were dumped into this pit.) He had to provide his own centrifugal pump and motor. By midafternoon, the desilter was discarding a large quantity of drilled solids. He remained with the unit until late that evening and it was performing superbly. He drove back home for the night and called the rig early the next morning to see how it was working. The toolpusher told him to come get that piece of *#@#&# (an oilfield versatile noun) because it wasn't working any more. When George arrived at the rig, he couldn't find his desilter bank. He asked the toolpusher if they had hauled it off. The toolpusher told him that it was right where he left it. The discharge line from the desilter bank had so many solids that it had plugged. The solids continued to build until the bank of cones buried themselves. He cleaned the solids from the discharge and the unit then continued to remove drilled solids.

In another illustration of introducing a new appliance to the oil patch, a gentlemen by the name of "Mr. Martin" visited our offices to discuss the latest in measurements currently being made on drilling rigs. He regaled a tale about how he and another fellow named "Decker" had introduced a device to the drilling rig that would measure how heavy the drill string was. He said the drillers resisted using the device because they didn't need it. The weight indicator was superfluous for them because they could "feel everything they needed to know" by the way the brake acted. Clearly, it would be almost impossible to drill wells now without the weight indicator. Still, the Martin-Decker weight indicator was not welcomed when it first was offered to the drilling rigs.

Not all new things introduced to the industry resulted from a quest to solve the problem which they approached. Mac McKinley was assigned a research project to help reservoir engineers map production zones. Usually, when drilling a field, geologist have to insert several faults to make their maps agree with the formations as they are drilled. Mac decided to try to use some micro-seismic techniques to see if faults could be located at some distance from wellbores. He wanted to detonate a small explosive in a wellbore and listen for the return echo. This would allow discoveries of faults in various directions away from the wellbore and also indicate their distance from the wellbore. While the explosive charge was being developed, he designed and built the listening device. In preparation for deployment, he found an abandoned well and gained permission to lower the new electronics into the well. When the sonde reached the bottom of the hole, he thought the electronics had completely failed at that pressure and temperature, because he had so much static. As he pulled the sonde from the hole, the static ceased. Puzzled about the electronics, he lowered the sonde back down the hole and the static began again. At one point in the well, he could start and stop the static. Looking at an old log of the well, that point was adjacent to a very permeable sand formation. There was flow behind the pipe. This, then, became the noise log used to validate that cement in the annulus does form a barrier.

Cement bond logs look at the interface between the cement and the pipe and the interface between the cement and the formation. Holes created by the migration of gas through the cement as it sets cannot be observed with cement bond logs. The noise log can detect the failure of the cement to form a barrier for flow in the annulus. This discovery was so important that he never did have the opportunity to return to his original assignment.

14.8 Gravity acceleration

The acceleration of gravity is not constant over the surface of the earth. The acceleration of gravity is higher at the equator than near the North or South Pole (Table 14-6). This has an impact on calculation of the gravitational force (or weight) of a body. For example, the moon's acceleration of gravity is one-sixth of the acceleration of gravity ("g") on the earth. If you weigh 180 lb on earth, you would weigh only 30 lb on the moon. On the other hand, if you have a drill string with a mass of 1,000 kg at the equator, the weight, in SI units, would be calculated by the product of mass x the acceleration of gravity (mg):

1,000 kg x 9.832186 m/sec^2, or 9,832 Newtons.

This same mass near the North or South Pole would weigh 9,780 newtons. Clearly, using SI units requires an adjustment in the value of the acceleration of gravity used to calculate weight.

As a matter of interest, the English system of units has a corresponding unit for weight — called the "poundal". The 1,000-kg drill string would have a mass of 22,000 lb. At the equator, the weight would be calculated the same way as using the SI unit system.

At the equator, the weight would be 22,000 lb x 32.25744 ft/sec^2, or 7,097 x 10^2 poundals; at the poles, the weight would be 7,059 x 10^2 poundals.

Table 14-6: Acceleration due to gravity at sea level.

Latitude Degrees	Ft/sec^2	Cm/sec^2
0	32.08730	978.0327
5	32.08858	978.0719
10	32.09240	978.1884
15	32.09865	978.3786
20	32.10712	978.6370
25	32.11757	978.9556
30	32.12969	979.3249
35	32.14310	979.7337
40	32.15741	980.1698
45	32.17218	980.6199
50	32.18696	981.0704
55	32.20130	981.5074
60	32.21476	981.9178
65	32.22694	982.2890
70	32.23746	982.6096
75	32.24599	982.8698
80	32.25228	983.0616
85	32.25614	983.1791
90	32.25744	983.2186

Without changing the value of "g" to account for the differences in weight, the SI system force measurements are accurate to a maximum of three significant figures.

One further note: the acceleration of gravity is also dependent upon the type of rock or formation. Surveys measuring the acceleration of gravity provide an indication of formations beneath the surface. In other words, "g" is not a constant across the face of this planet.

Appendix 14A: Centrifugal pump

If you answered "not as high", you are in a majority of respondents — but incorrect. A centrifugal pump is a constant head device. This means that the heavy drilling fluid would rise in the casing to the same height as the water. If this is not clear, a deeper, better understanding of centrifugal pumps should be acquired. The amount of power required will increase as mud weight increases, BUT any fluid (including blue smoke) will rise to the same height.

The flow rate depends entirely upon the plumbing connected to the pump. The shut-in pressure (no flow) will provide the pressure for the head produced by the impeller. This head will remain constant as the shut-in valve is slowly opened. After increasing the flow, the head will start decreasing because of the pressure (or head) loss within the pump itself. There would be a larger pressure drop with a small pump (like a 2 in. x 3 in.) than a larger pump (like a 6 in. x 8 in.) if fluid was simply pumped through the pumps without them running.

Many centrifugal pumps are used in drilling systems. If an incorrect impeller is installed because of a lack of understanding of centrifugal pumps, many problems can arise.

Frequently, the concept of head is confused with pressure. In well control classes, the pressure at the bottom of a hole is calculated with the equation:

Pressure (psi) = 0.052 (mud weight, ppg) (head, ft)

Sometimes the 'head" is written as "depth" but it is the same concept. When a centrifugal pump is pumping fluid, the head will remain the same, but the discharge pressure will increase as the mud weight increases.

INDEX

Index Terms	Links			

C

Index Terms	Links			

D