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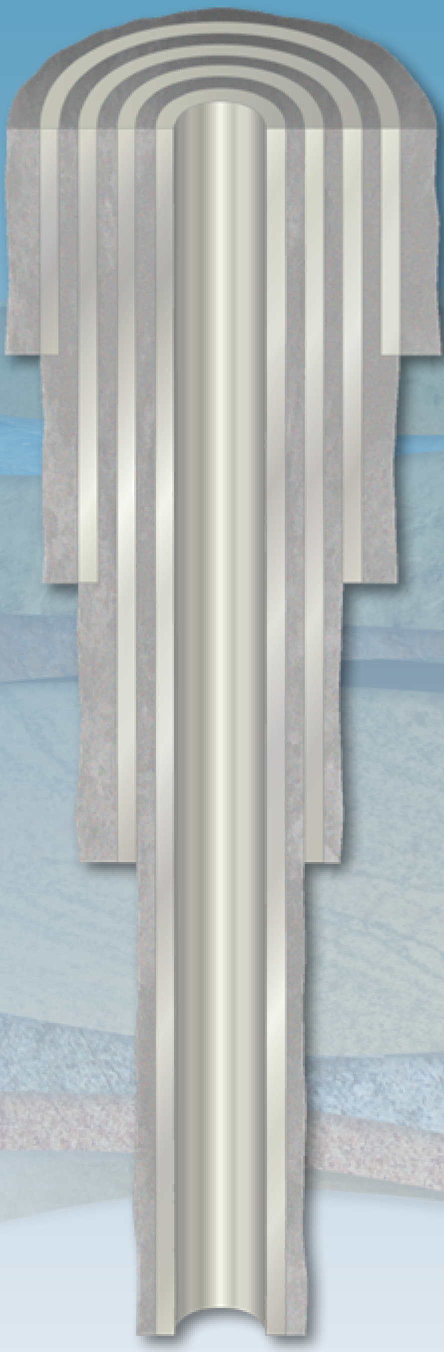

WHITE PAPER

Common Well Cementing Problems and Solutions

Gunnar DeBruijn

CONTENTS

I. Abstract

Throughout the well's life cycle, cement serves as the foundation. There are several issues associated with well cementing that can impede the well construction process, reduce well production, and be costly to resolve. If problems can be identified and prevented prior to the cement job, or mitigated during the cement job, costly remediation can be avoided.

The design and planning phase of the cement job is a critical step where common cementing problems can be prevented. Understanding potential problems and indicators is the key to preventing and mitigating problems should they arise during the cement job execution.

Common cementing problems addressed in this paper are: gas flow (after cement placement), zonal communication, stimulation communication between stages, poor displacement efficiency, cement failure, fluid influx (during pumping), lost circulation, poor pumpability, wet shoe track, lifted casing (during pumping), and low top of cement (in the annulus or when tagging plugs).

Common cementing problems can generally be avoided by properly planning and preparing for the cement job, including mitigation strategies in the cement program, and installing the cement according to the program.

II. Introduction

Cement is the foundation for a well through the life cycle of the well. Problems that impair the well construction process or reduce the production of the well are costly to remedy. If problems can be identified and prevented prior to the cement job or mitigated during the cement job, costly remediation may be avoided.

It is critical to properly interpret observations during the cement job to identify potential problems. During job execution, minor changes or contingency plans may be implemented to mitigate further well challenges. In cases where mitigation is not possible, lessons can be learned for the next cement job.

Remediating a cementing problem is often costly and is not always successful. Remediation typically involves a cement squeeze during drilling, production, or final abandonment. Preventing the problem prior to cementing is the best way to avoid costly remediation work.

Readers are encouraged to read "Applied Well Cementing Engineering" (Liu, Gefei, 2021) for a full discussion about cement job design. A good design that avoids most problems will include a sensible mud removal strategy, high quality fluids and spacer, coherent slurry design, and the support of computer simulations of a representative well. A flawless cement job execution includes appropriate contingency plans.

Common cementing problems that are addressed in this paper are:

- Gas flow (after cement placement)
- Zonal communication
- Stimulation communication between stages
- Poor displacement efficiency
- Cement failure
- Fluid influx (during pumping)
- Lost circulation
- Poor pumpability
- Wet shoe track
- Lifted casing (during pumping)
- Low top of cement (annulus)
- Low top of cement (when tagging plugs)

Pre-cement job prevention of the problems will include many similar themes.

1. **A Good Centralization Program**
   A centralization program is designed so that the casing is as close to the center of the hole as possible or centered enough to allow for good mud removal. A simulation is performed using the proposed centralizer program to predict how close the casing is to the center of the hole and running forces calculation is performed to see whether the casing will be able to be run to the bottom. The running forces calculation may also indicate if it will be possible to pull the casing out of the hole as a contingency plan.

2. **A Good Mud Removal Plan**
   The mud removal plan includes the fluids design and pumps schedule that will be used in the wellbore together with the simulated casing centralization. The fluids program includes a spacer with the rheology and density hierarchy that will allow displacement of the mud. The spacer will need to be compatible with both the mud and the cement and have sufficient volume to be able to effect mud removal. Mechanical plugs (bottom plugs) may be deployed to minimize contamination of the spacer.

The density of the spacer is an important aspect of the mud removal strategy. The density of the spacer should be greater than the density of the fluid it will be displacing (the mud) and less than the density of the fluid that will be displacing the spacer (the lead cement). A density hierarchy of 10% difference between fluids is considered a good design methodology. Many wellbore constraints may not allow for such a large density difference, and in some cases, a density hierarchy of 0.2 ppg[1] may suffice to provide the density hierarchy. Gravity will always pull the heavier fluid downwards.

The rheology of the spacer is another important component of the mud removal plan. The spacer rheology should be greater than the fluid that it will be displacing (the mud), and less than the density of the fluid that will be displacing the spacer (the lead cement). A rheological density hierarchy of 20% difference between the fluids is considered to be a good design criterion. The rheology of the mud, spacer, and cement all change with temperature, pressure, and time so the rheological hierarchy should be evaluated across the entire range of conditions that the fluids will be exposed to during the job. Cementing hydraulics computer simulations may help evaluate the rheological hierarchy.

The spacer needs to be compatible with the mud and the cement. API[2] 10B-2 "Recommended Practice for Testing Well Cements" (2016) describes methods for testing spacer compatibility. The volume of the spacer needs to be enough to fulfill the mud removal requirements. For initial volume estimates, rules of thumb such as "500 ft of annular length" or "10 minutes of contact time" may be used. However, a computer simulation will help to evaluate the required volume. Note that contamination of the spacer occurs at both the leading edge and trailing edge of the spacer and with the long wells or large casing. The entire volume of the spacer may be mixed with cement or mud before reaching the bottom of the well. A computer simulation is useful for evaluating the amount of contamination that may affect the spacer.

Mechanical plugs (bottom plugs) may be used at the fluid interface (the mud/spacer, or spacer/cement, or both) to minimize the contamination of the spacer. A bottom plug may prevent the contamination of tens of barrels (bbl) of a spacer, or it may be necessary to increase the spacer volume by 50 bbl or more if a bottom plug is not used. A computer simulation can be used to assess the usefulness of bottom plugs.

[1] Pounds per gallon
[2] American Petroleum Institute

3. **Good Slurry Design**

The slurry should meet the performance requirements defined for the well. The cement must meet the compressive strength and volume requirements, typically defined by regulations. The slurry should be tested for performance using the methods described in API[1] 10B-2, “Recommended Practice for Testing Well Cements”. The slurry must have sufficient thickening time to allow the placement of the cement. Other slurry performance parameters include rheological properties, static-gel strength development, fluid loss control, slurry stability (both free fluid, and sedimentation), and set slurry mechanical properties. Slurry design is a large topic and readers are encouraged to read chapter 5 in “Applied Well Cementing Engineering” (Liu, Gefei, 2021).

The slurry should be tested in the lab to understand the performance envelope of the cement. Representative samples of the cement should be used for the testing. Although not every lab test is required for every cement job, lab testing should be proportional to the desired slurry performance. Cement type, blend, additives, mix water requirement, density, and yield are what defines a slurry.

4. **A Representative Computer Simulation**

A representative computer simulation is a valuable aid for the cement job design. The simulation can aid in the development of the centralization program and mud removal strategy. It can also be used to create a temperature and pressure schedule for the cement lab tests performed prior to the job. The hydraulics simulation will be useful for determining the expected pressures during the job, as well as well control and fluid displacement in the annulus. A computer simulation may aid in the calculation of critical static gel strength along the whole wellbore and can be used to assess the risk of gas migration. Readers are encouraged to read chapter 7 in “Applied Well Cementing Engineering” (Liu, Gefei, 2021) for a full description of the process of developing a cementing simulation.

5. **Cement Job Execution According To The Program**

A cement program is designed to prevent problems. Job execution according to the planned program is the key to success. The well site execution should be performed by mixing fluids to the correct density, pumping the fluids at the programmed pump rate, and using the programmed volumes of fluids (spacers, lead slurry, tail slurry, and displacement). Readers are encouraged to read chapter 10 in “Applied Well Cementing Engineering “(Liu, Gefei, 2021) for a full description of the cement job execution process from blending cement through to bumping the plug, equipment clean up, and post job reporting.

[1] American Petroleum Institute

Tolerances and contingency plans designed into the cement program allows the job objectives to be met even if operational problems prevent execution exactly to the plan. The contingency plan may include a “circulate out and re-start” option if the tolerances cannot be met.

Managed pressure cementing operations involve not only pumping the correct fluids down the casing but also managing the annular pressure on the returns side. Executing the cement job according to the schedule is important for managed pressure cementing operations.

III. Sign, Cause, Prevention, Mitigation, and Remediation

1. Gas Flow (After Placement)

Gas flow after placement is the unplanned and unwanted gas moving in the annulus. Because gas has low density, it typically migrates up the wellbore.

Sign (Observation)

There are several indications of unwanted gas moving in the annulus. There may be signs at the surface including gas bubbling at the surface around the well, abnormal annular casing pressure, or a surface casing vent flow.

In cases where gas migrates to a shallow zone and does not migrate to the surface, the only indicator may be the presence of gas on cement evaluation logs. Figure 1 illustrates gas migrating up the annulus.

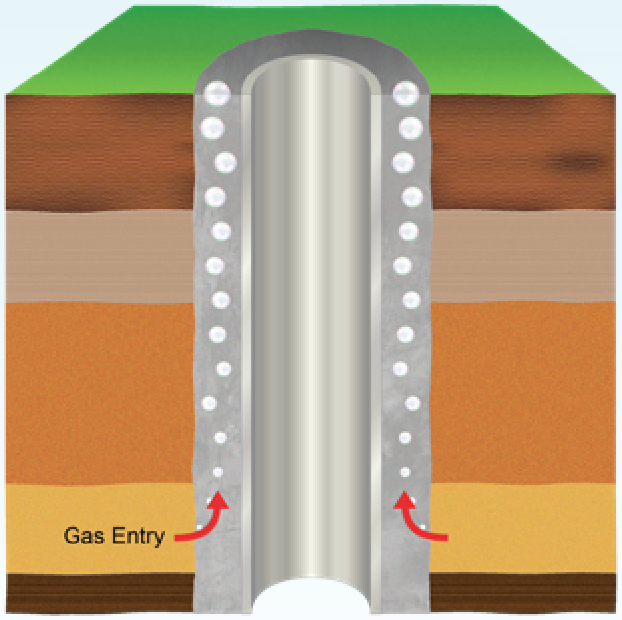

Figure 1: Gas Migrating Up The Annulus

If there is water at the wellhead and the water is bubbling like boiling water that is an indication of high-volume gas migration. Bubbles that occur at a rate of only a few bubbles per minute indicate a low-volume gas migration.

Surface Casing Vent Flow (SCVF) and Annular Casing Pressure (ACP) are both indications at the surface that there is gas migration in the annulus to the wellhead.

SCVF is a flow of gas to the surface casing vent. The Alberta Energy Regulator (AER) describes a method to determine if there is SCVF. Figure 2 is an image of a bubble test on a slant well where a hose is connected to the surface casing vent and submerged under 2.54 centimeters of water. If there are 2 bubbles in 10 minutes then this test fails, indicating gas at the surface. A failed bubble test is followed by a gas flow rate determination with a meter attached to the surface casing vent. After the gas flow rate is determined, the flow may be classified as “Serious” or Non-serious” according to AER directive 87.

Figure 2: Testing For Surface Casing Vent Flow (Credit: Gunnar Debruijn)

ACP[1] is similar to SCVF[2] because gas is indicated on the surface. ACP[1] is measured as a pressure build-up rather than a flow rate. API[3] has published recommended practice API[3] Recommended Practices 90-1 and 90-2 which describe annular casing pressure management for offshore and onshore wells respectively. Each of these documents describes how to measure and monitor annular casing pressure. These API[3] recommended practices also describe potential sources of annular casing pressure including thermally induced pressure, operator-imposed pressure, and sustained casing pressure.

Cause

There are many possible causes for gas flow in the annulus of a well. Bexte et al (2008) discuss the reasons for gas migration in a well, and Nelson and Guillot (2006) devote the entire chapter 9 in Well Cementing for the discussion of annular flow. Using physics principles, we can link gas flow back to three root causes. Figure 3 describes these generic root causes for gas flow, and all three need to be present to allow gas to flow:

- Pressure gradient – the pressure in the annulus falls below the gas pressure in the formation, so that gas flows to the lower pressure space
- Space for gas to enter – pore space (in the annular material) is available for the gas to enter into. Liquid that can be displaced by the gas may also be present.
- Flow path – a path is available for the gas to migrate upwards. This path may be created by the migrating gas or may be formed as a liquid path that the gas migrates up.

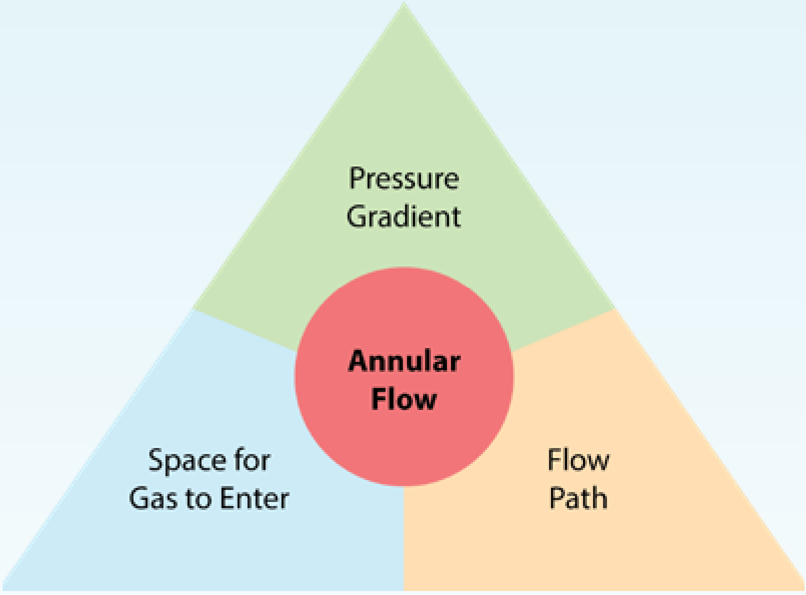

Figure 3: Cause For Annular Gas Flow

[1] Annular casing pressure
[2] Surface casing vent flow
[3] American Petroleum Institute

The definition of when the pressure in the formation is greater than the pressure in the pore space of the cement in the annulus may be described by the critical static gel strength calculation. Critical static gel strength is discussed in API[1] Standard 65-2.

The time the slurry takes to change from a liquid to a solid is related to the risk of gas migration. The slurry maintains a hydrostatic force on the formation when it is a liquid. At the point where it reaches the critical static gel strength (CSGS), gas can migrate into the slurry. Once the slurry reaches 500 pounds per 100 ft^2 it is considered impermeable to gas. The time that it takes for the slurry to go from the CSGS to 500 pounds /100 ft^2 is called the critical gel strength period (CGSP).

The equation for critical static gel strength is:

$$\text{CSGS} = \frac{(\text{OBP})(300)}{(L / \text{Deff})}$$

Equation 1: Critical Static Gel Strength Equation

Where
- OBP = Hydrostatic overbalance pressure (psi[2])
- 300 = conversion factor (lb/in)
- L = Length of the cement column (ft) above the potential flow zone
- Deff = DOH - Dc

Where
- DOH = Diameter of the open hole (in)
- Dc = Diameter of the casing

Nelson and Guillot (2006) also explored several other factors that affect gas migration by allowing space for gas to enter or a gas migration path. These factors include fluid loss from the cement slurry, cement shrinkage, cement permeability, free fluid, mud removal, microannulus, and cement sheath mechanical failure.

Pre-Cement Job Prevention

Preventing gas migration is done by removing any, one, or even all three of the root causes for gas migration in the annulus.

[1] American Petroleum Institute
[2] Pounds per square inch

The best method for preventing gas migration is to eliminate the flow path for gas migration by having an excellent job design, which includes a good centralization program and a good mud removal plan.

Eliminating the pressure gradient as a root cause of gas migration is done by keeping the annular pressure overbalanced and minimizing the time that the pressure gradient exists by utilizing a slurry with a short transition time from CSGS[1] to 500 lbs/100ft^2.

High-performance slurries can also be planned to prevent gas migration by minimizing the space for gas to enter the slurry. These slurries generally have very good fluid loss control (API[2] fluid loss < 50ml/30 minutes) which prevents cement filtrate from leaking off into the formation. High solids volume slurries minimize the pore space in the cement matrix thus minimizing the spacer for entry. These slurries may also incorporate specific gas migration control additives which also minimize the permeability and porosity of the set cement, reducing the opportunity for the gas to enter the cement sheath.

High-performance slurries may also be non-shrinking and incorporate mechanical properties that ensure isolation through the life of the well. A non-shrinking cement will maintain the bulk volume through the setting process. Incorporating a mechanical parameter into the cement design such as low Young's modulus (which implies flexibility in the set cement) will prevent the cement sheath from failing mechanically during the temperature and pressure cycles of the well. A mechanical failure will present as a crack that can be a path for gas to migrate.

Mitigation During the Cement Job

The primary mitigation for preventing gas flow after placement is to execute the cement job according to the program.

Remediation

Solving a gas migration problem is typically difficult and costly. To determine the leak path, cement evaluation logs can be used. The leak path is then perforated, a cement squeeze is performed, and the well is checked to see if the gas migration problem has been resolved.

Gas migration paths are typically quite small. The squeeze material may need to be a resin-based material, a microfine-based cement, or a very low fluid loss cement that can penetrate the gap and seal the leak.

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[1] Critical static gel strength
[2] American Petroleum Institute

2. Zonal Communication

Sign (Observation)

Zonal communication is often observed during the well production. Water or gas from a zone that should be separate from the producing zone is evident in the production indicating communication behind the casing. Unwanted water and gas production may be investigated with production logs to identify the position of the flow and cement sheath evaluation acoustic logs to interpret potential flow channels.

Zonal communication may also be observed as shallow pressure when drilling offset wells nearby. A lower zone may communicate with a shallower zone and “charge” it, posing a hazard to drillers.

Figure 4 illustrates some potential flow paths for unwanted water or gas. There are many potential flow paths for water, oil, or gas in the annulus because the wellbore penetrates the earth strata.

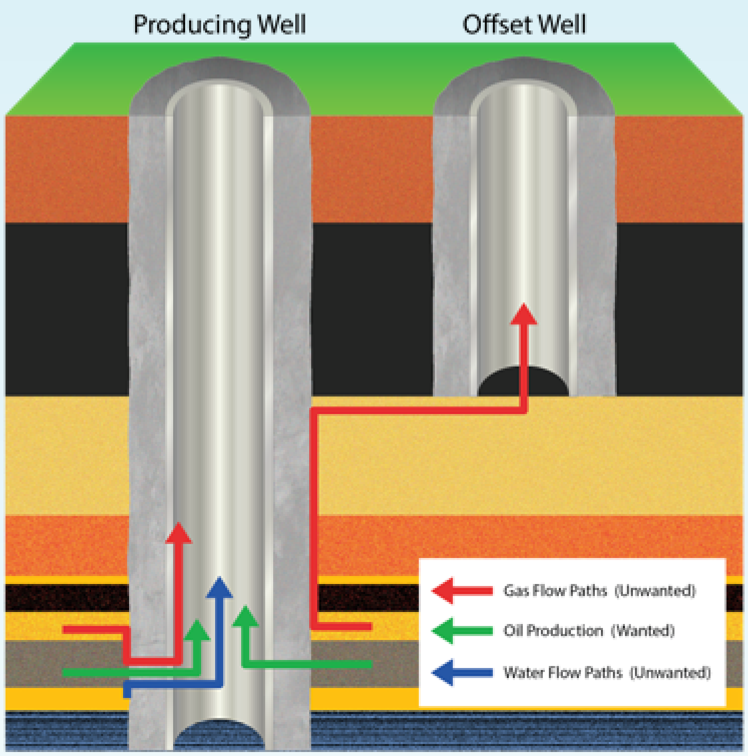

Figure 4: Zonal Communication Potential Flow Paths

Cause

Communication between zones is caused by allowing a pathway to exist for the fluid to communicate between the zones. This path is typically created because a mud channel has been created in the annulus where the fluid can migrate.

Small gaps may also exist in the annulus that allows zonal communication. A microannulus, for example, may allow enough space for gas to migrate between zones. Casing corrosion and poorly bonded cement to the casing or the formation may also allow enough space for communication.

Pressure or temperature cycles of the cement sheath can also cause the cement to fail (crack) if the mechanical capabilities of the set cement are exceeded. Once a crack forms, gas or fluid may pass through the crack.

Pre-Cement Job Prevention

Eliminating the gas migration flow path is the most efficient method of preventing annular communication and gas migration. This requires excellent job design that includes a good centralization program and efficient mud removal plan.

Mitigation During the Cement Job

The primary mitigation for preventing any annular flow or zonal communication after the cement job is to execute the cement job according to the program.

Remediation

Solving zonal communication problems is typically complex and costly. Cement evaluation logs may be run to determine the leak path. A remedial cement squeeze typically follows perforation of the leak path. Logs can be run again, and the well can be put back on production to determine if the unwanted water or gas production has been reduced.

Cross-flow communication paths that charge shallower formations are difficult to remediate. The primary mitigation is for drillers to be aware of taking appropriate precautions as they drill through the charged zone. A cement squeeze in the leaking well may prevent further pressuring of the shallower formation.

Many methods can be used to access the communication path in need of sealing before the well is abandoned. Typical remedies for cement squeezes involve perforating the area where the suspected leak path is. Other methods may involve cutting a slot in the casing using an abrasive tool or a casing mill. Recent developments include a perforation and wash tool.

3. Stimulation Stage Communication

Stimulation stage communication is defined as fluid communicating from one stimulation stage (fracture stage) to a previously stimulated stage. It occurs when stimulation fluids travel from one stage to a previous stage. The desired stage is not effectively stimulated, thus resulting in lower production. Figure 5 illustrates the stimulation fluid traveling from stage 4 to the previously stimulated stage 3.

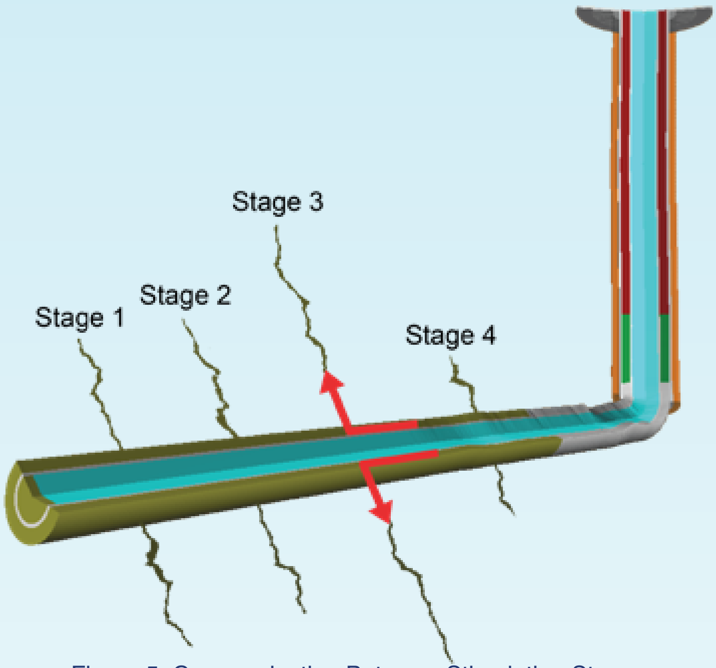

Figure 5: Communication Between Stimulation Stages

Sign (Observation)

Signs of communication between stages during stimulation may not be obvious and are difficult to diagnose. The result of communication between stimulation stages on the well is less effective stimulation, resulting in lower production. Identifying stimulation stage communication requires engineers of the drilling, cementing, and stimulation departments to communicate.

Instrumentation during stimulation may help understand possible communication between stimulation stages. In SPE Paper IPTC 19779 (2020), Perroni, et. al describes a methodology that identifies whether stimulation stages are communicating with each other. Stimulation breakdown pressures may be analyzed. If a packer is used with pressure and temperature gauges, the data can also help determine if there is pressure and or fluid communication. This paper indicates that more than 30% of stages may have communication with previously stimulated stages.

Production results are also an indication of how successful the stimulation is. Many factors can affect well production, and it may be difficult to misattribute poor production results to poor cement isolation.

Cause

A flow path between perforation or stimulation stage intervals can allow stimulation fluids to travel between stages. A free water channel or a mud channel can carve the flow path between stimulation intervals. A micro-annulus may be sufficient for pressure communication but may not provide enough flow area to enable fluid communication between stages.

Communication between stages can also happen outside the cement sheath in natural or induced fractures. Although, this communication is not related to the primary cement job.

Pre-Cement Job Prevention

Preventing communication between stimulation stages can be done during the design phase of the cement job with a good centralization strategy, spacer design, mud removal program, and cement slurry design.

An effective centralization program will enable good mud removal, allowing effective placement of cement that can isolate stage intervals. The centralization program can be optimized for centralization of the casing along the entire length of the casing or just for selected intervals. One can expect isolation near the centralizers. In horizontal wells, centralization programs often call for one or more centralizers per joint to achieve centralization. There should be at least one centralizer between the expected stimulation stages. If no centralizers are present, casing rotation may be considered to achieve cement placement all around the pipe.

A good fluid plan is required to achieve good cement placement. This includes a spacer fluid that is compatible with both the mud and cement with sufficient volume to achieve mud removal. The spacer fluid should follow the density and rheology hierarchy requirements for good mud removal.

The cement slurry performance characteristics also contribute to preventing communication between stages. A slurry that exhibits zero (0) free fluid will not develop a free fluid channel at the top of the well. The slurry should also follow the density and rheology hierarchy requirements to displace the spacer fluid ahead of it. Some slurries may also include reactive components that react with the mud film to seal small gaps in the annulus.

Remediation

Communication between stimulation stages is typically observed only long after the cement job and during or after the stimulation treatment. There is no recourse other than to design the next well so that the same communication does not occur.

In cases where pressure testing identifies casing leaks or stimulation stage tool leaks, a remedial squeeze may be performed to seal the leak.

Post job cement evaluation together with stimulation evaluation is the best method to identify communication between stimulation stages and create a design to prevent the potential communication in the next well.

4. Poor Displacement Efficiency

Sign (Observation)

Poor mud displacement may not be evident until after the cement job. The most usual indication of poor displacement efficiency is unsatisfactory cement bond logs. Signs of gas migration, zonal communication, or communication between stimulation stages are also evidence that there is poor displacement efficiency of the mud, spacer, lead slurry, or any of the cementing fluids. During a cement job, if fluids such as spacer or cement arrive early in the returns, it may be an indication of channeling which is the result of poor displacement efficiency.

Figure 6 illustrates spots in the annulus where the mud may not be displaced well. Position ‘a’, the narrow side of the annulus is the most typical area of poor displacement, areas ‘b’, ‘c’, and ‘d’, indicate that displacement can be compromised along the borehole wall, casing, or even in the wide side of the pipe, especially where there are over gauge sections of the borehole.

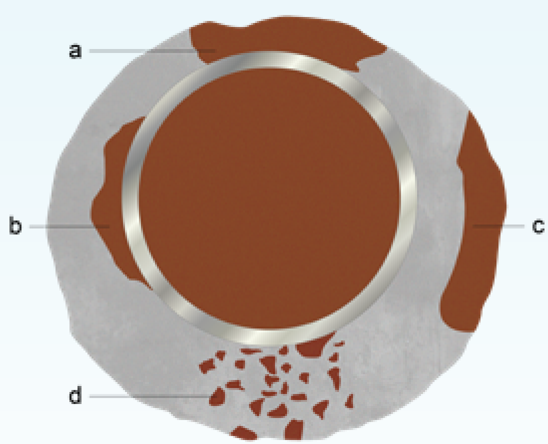

Figure 6: Poor Displacement Efficiency

Cause

The root causes of poor displacement efficiency can usually be traced back to the design. Centralization and fluid properties are significant influencers of displacement efficiency. Poor job execution may also lead to poor displacement efficiency.

Centralization and fluid properties are key factors of affecting displacement efficiency. If the casing is not well centralized, it will be difficult to displace fluids on the narrow side of the casing, which will lead to channels. If fluids (spacer, lead slurry) are not designed with a density and friction pressure hierarchy, the displacing fluids will tend to channel through the fluids that they are displacing in the wellbore.

The execution of the cement job is also a factor; fluids not mixed to the programmed density lack the rheological properties to effectively displace the fluid ahead. For example, if the lead slurry is mixed at a lower density than programmed, the slurry will be "thinner," have lower viscosity, and will channel through the fluid (i.e., the spacer) ahead of it. If the fluids are not pumped at the programmed pump rates, the displacement efficiency may be outside of the optimized rates that were simulated before the cement job and channeling may also occur.

Pre-Cement Job Prevention

The importance of the centralization program cannot be overstated; centralization is the key. If an effective centralization program is not possible, a casing rotation plan may be incorporated into the cement design. If casing rotation is desired, it should be planned for by simulating the torque and drag and checking that the casing connections have sufficient strength for rotating during the cement job. CEMPRO+ can be used to simulate torque during cementing.

In general, increasing the number of centralizers will improve the centralization and thus the displacement efficiency. A centralization simulation (i.e., CEMPRO+) can be used to determine the optimum number of centralizers. The final centralization will be a result of all the wellbore parameters (hole size, casing size, casing weight, centralizer model and performance, fluid properties, and well deviation).

Some rules of thumb for casing centralization:

Well Inclination	**Centralizer Spacing**
Vertical	1 centralizer every 4 casing joints
Vertical < casing < 30 degrees	1 centralizer every 3 casing joints
30 degrees < casing < 60 degrees	1 centralizer every 2 casing joints
60 degrees < casing < horizontal	1 centralizer every casing joint
Horizontal	3 centralizers every 2 joints

The number of centralizers to run needs to be discussed and debated with the drilling department. There may be diminishing incremental improvements with more centralizers. For example, in horizontal wells, although 3 centralizers every 2 joints may provide the best mud displacement, 1 centralizer per joint may provide sufficient centralization to achieve the mud removal objectives. There is a perception that centralizers may add drag force that can prevent the casing from running to the bottom. Centralizers will reduce casing buckling tendencies and can aid in casing running. A centralization simulation along with torque and drag analysis will give engineers confidence to run casing to the bottom even through extended or horizontal wells. Software like CEMPRO+ can provide the required simulation.

A good mud removal plan and fluid design are essential for planning efficient displacement. A density hierarchy and friction pressure hierarchy are critical. In horizontal sections, the fluids rheology and friction pressure hierarchy will enable good mud removal.

Increasing spacer volumes may also improve the displacement efficiency. A hydraulic simulator can be used to understand how much of the spacer is contaminated as it travels down the casing and up the annulus. Spacer volumes may be increased to compensate for the contamination. Bottom plugs may also be used to separate the fluids and effectively provide more uncontaminated spacer volume at the shoe.

The spacer fluid itself is also important. Compatibility and stability in the downhole temperature and pressure conditions contribute to effective displacement. The spacer and cement fluids should be fully tested in the lab before the job execution. A hydraulic and temperature simulator (i.e. CEMPRO+) can be used to develop the temperature and pressure schedules that should be used in the lab.

Simulation of the cement job is the best mitigation for poor displacement. A hydraulic simulation that includes the centralization (i.e., CEMPRO+) helps to visualize the displacement and can be used for sensitivity analysis to understand how each component of the job design contributes to good mud removal. The simulator can be used to optimize the cement job design to achieve the desired mud displacement.

Mitigation During The Cement Job

The primary mitigation for preventing poor displacement efficiency is to execute the cement job according to the program. Fluids should be mixed to the designed density and pumped at the rates that have been confirmed by the simulation to provide effective mud removal.

Casing rotation during the cement job can also aid in fluid displacement. Casing rotation should only be applied if the connections (both casing and liner connections if used) have sufficient strength for the torque that will be applied.

Remediation

Poor displacement efficiency is typically observed only long after the cement job.

In cases where poor displacement leads to gas migration or zonal communication, a remedial squeeze may be performed to seal the leak.

Post-job cement evaluation is the best method to identify and quantify the displacement. The execution of the cement job can be analyzed using a cementing simulator such as CEMPRO+. Cement evaluation logs can be run, and the results can be compared to the simulation. Once the evaluation logs have been analyzed, a remedial cement squeeze can be designed to fill the channels with cement.

5. Cement Failure (Due to Stress or Corrosion)

Sign (Observation)

Cement failure is typically observed when there is a leak path and unwanted gas migration or other fluid flows in the annulus.

If there are leaks and the results of a cement evaluation bond log is unsatisfactory, the cause may be cement failure.

Cause

There can be several reasons for the cement to fail and develop leak paths. Before blaming the cement, the centralizer program and displacement efficiency should be checked to ensure that there are no mud channels causing the leak paths. After other factors have been eliminated, the cement's performance can be evaluated.

Cement failure occurs if the stresses that are placed on the cement exceed the strength of the cement. If the compressive loads exceed the compressive strength of the cement, it will fail in shear. If the pressures in the casing put a tensile load on the cement sheath, then the cement will fail in tension and cracks will occur along the axis of the wellbore. Figure 7 illustrates possible tensile cracks in the cement sheath. Cement strength is one component of the well system that should also consider the casing properties and formation properties surrounding the cement. The risk of cement tensile failure is greatest in soft formations.

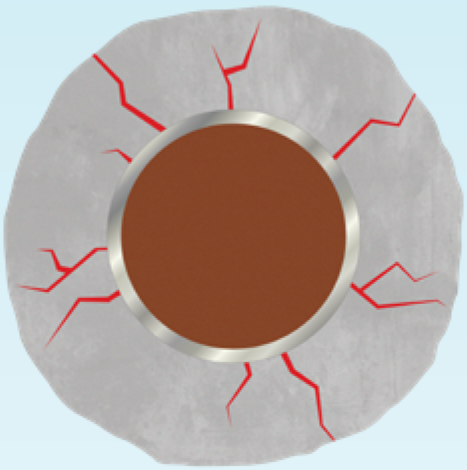

Figure 7: Cement Failure With Tensile Cracks In The Cement Sheath

Cement failure may occur with the application of excessive pressures and temperatures. Pressure testing as the cement is setting may crack the cement. In steam injection wells, fast heat-ups will stress the cement sheath more than gradual warming. Temperature increases will expand the casing causing stress to the cement sheath.

Cement contamination or poor density control during cementing can cause the cement to have lower strength performance.

Corrosive fluids in the annulus such as carbon dioxide and sulfates at low temperatures, can degrade the strength performance of the cement throughout the life of the well.

Pre-Cement Job Prevention

To prevent cement failure is to have a good centralization program, a good mud removal plan, and a good slurry design. For wells that will see significant stresses in the life cycle, a stress simulation can be performed to assess the mechanical performance of the cement.

Cement slurry optimization can prevent cement failure. Typically, a cement with a lower Young's modulus will perform better in high stress environments. A Young's modulus lower than that of the formation will ensure that the cement is flexible enough to withstand the stresses. There are several flexible types of cement on the market. Foam cement is considered to be flexible cement. Software with foam cement modeling capabilities such as CEMPRO+ should be used to optimize the foam cement design.

For corrosive environments, the cement should have as low permeability (typically high solid volume fraction (SVF) as possible to avoid the penetration of the corrosive fluids. Carefully chosen base materials can also minimize corrosive effects. For example, high sulfate resistant (HSR) cement can maximize sulfate resistance. Another example would be to minimize the Portland cement in the blend where CO_2 resistance is desired.

Remediation

Remediation for cement failure involves assessing the failure, and then performing a cement squeeze if necessary. Cement evaluation logs may need to be run to determine the location of the failure.

6. Fluid Influx During Cementing

Sign (Observation)

A common observation made of influx during cementing is that the flow at the return line is faster than the pump rate. Influx occurs when the wellbore pressure is lower than formation pressure. Figure 8 illustrates the influx of fluids from the formation into the cement column.

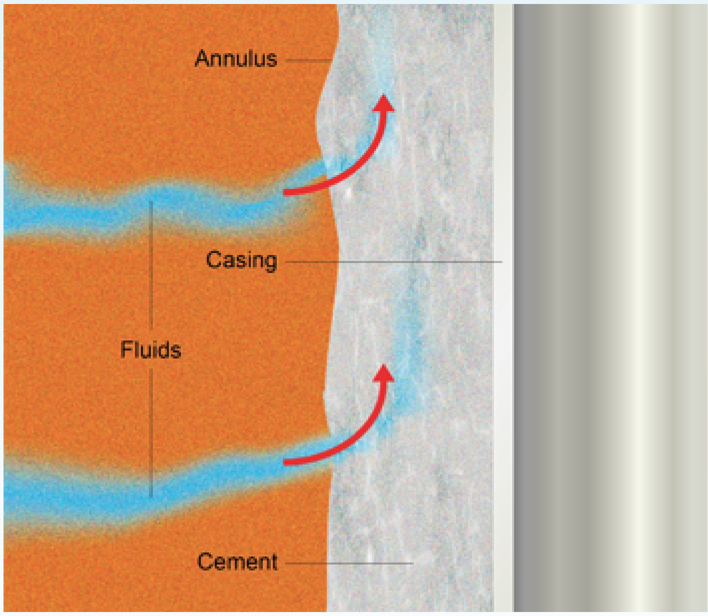

Figure 8: Influx Of Fluid Into The Cement Column

An influx can occur before, during, or after cementing operations.

The most severe (and possibly catastrophic) form of an influx during cementing is a blowout. Formation fluids enter the annulus, increase the flow, and unload the annulus of drilling fluids and cementing fluids. This results in the well producing formation fluids up the annulus.

Influx detecting while cementing should take into account the changes in flow rates during U-tubing of cementing operations. A small increase in the return rate does not always indicate an influx. While mixing cement, the cementing fluids weigh more than the drilling fluid so the fluids are U-tubing, and the returns rate is faster than the pump rate. This outcome should not be mistaken for an influx and can be predicted using simulations such as CEMPRO+. Just after the plug is bumped, the thermal expansion of the fluids in the annulus may also present a slow flow rate.

There are three different times influx may occur. The first is just prior to cementing operations. The second risky time is just as cement rounds the shoe, especially if water or an unweighted fluid is used as a spacer. This is the time that the annulus is the lightest. With weighted spacers in widespread use, this risk is under control. However, from a design point of view, this is the point that we have to check for how close to balance we are. As managed pressure drilling operations become more widespread, more issues may be seen just as the cement rounds the corner. The third time is just after bumping the plug and as the cement sets, going through the gelation phase and the critical gel strength period.

An unexpected change in pump pressure can also be a sign of influx. Detecting an influx from pump pressure though is not intuitive and unreliable. Pump pressure may be reduced because the annulus has a lower equivalent circulating density (ECD) with the influx. Alternatively, the pump pressure may be slightly higher than anticipated due to extra friction pressure from additional flow in the annulus.

One special case of influx is from ballooning of the formation. If there have been significant losses during circulation before cementing, and a flow check indicates flow prior to cementing, it is possible that the formation can continue to deliver fluids to the wellbore during and after cementing operations.

Other cases of influx can occur after cementing operations. This influx may be due to shallow gas or shallow water flows. If there is shallow gas flow, evidence of bubbles may be seen around the wellhead after cementing. If the water flow is shallow, there may be evidence of fluid flow around the wellhead.

Cause

Fluids will flow from higher pressure to lower pressure. If the hydrostatic in the annulus is less than the fluid pressure in the formation, fluids will flow from the formation to the annulus, causing an influx.

If ballooning has been occurring in the well, a fracture system may contain fluid that is pressured to the fracture pressure of the formation.

As the cement is setting and gaining gel strength, the hydrostatic pressure in the cement column may drop below the formation pressure during the critical hydration period before the slurry becomes impermeable.

If water or a light fluid is used as a preflush, the annulus has the lowest equivalent circulating density (ECD) when the lightest fluid is in the annulus at the casing shoe. If the ECD falls below the formation pressure, an influx can occur. Too much water or other low-density fluid pumped prior to the cement job causes the annular pressure to fall below the formation pressure.

Managed pressure drilling operations can also increase the risk of an influx. In managed pressure drilling operations, the drilling fluid may have a lower ECD than the formation pore pressure. The ECD is maintained above the formation pressure with a combination of the drilling fluid density, pump rates, and the choke setting at the return line. An influx occurs if the pressure at the formation falls below the formation pressure during cementing operations.

Loss circulation can also lead to a fluid influx. If losses become severe, the fluid level in the annulus can drop, thus lowering the hydrostatic pressure in the annulus and then causing an influx.

Pre-Cement Job Prevention

Formation pressures should be anticipated as part of the drilling program. The drilling fluid program is designed to prevent influx during drilling and cementing. Managed pressure drilling operations should combine with drilling fluid density, pump rates and choke setting to maintain the annular pressure.

The primary method to prevent an influx during cementing is to have a fluids program that maintains the annulus pressure above the formation pressure. A hydraulics simulation such as CEMPRO+ can be used to predict whether the annular pressure will be maintained during the cement job. If water or another low-density fluid is used as a preflush, the simulation can be used to predict that the annular pressure will be maintained above the formation pressure. Water volumes may be reduced to maintain annular pressures throughout the cement job. It is important to use simulations to design a cement job so that losses resulting in an influx do not occur.

Another important step before cementing is to perform a flow check on the well. No flow during a flow check ensures that the drilling fluid is maintaining pressure on the wellbore and there is no ballooning. If flow is detected during the flow check, cementing operations should not be started. If ballooning has occurred, the flow should be allowed to continue to deplete until there is no flow. If there is flow due to shallow water or shallow gas flow, steps must be taken to control the flow before cementing.

To prevent shallow gas or shallow water flow, annular pressure may be applied. The application of annular pressure should be planned prior to the job so that the required equipment are prepared.

Mitigation During The Cement Job

Preventing gas flow after placement typically requires executing the cement job according to the program. It is especially important to mix the fluids to the correct density and pump the programmed volumes at the scheduled pump rate.

If an influx is observed such as shallow water flow or shallow gas flow, annular pressure may be applied after bumping the plug. The procedures for applying annular pressure will be specific to the casing string, wellhead, and equipment available at the well site.

Managed pressure operations are a special case where the annular pressure can be changed with the application of the choke during cementing operations. An influx can be mitigated by applying additional pressure on the annulus. The limit for the additional pressure will be lost at the weak zone.

In the rare case where influx is at significant volume, the operation will change from a cementing operation to a well control operation.

Remediation

The immediate response to influx is stopping flow. This may be as simple as increasing the annular pressure or closing the BOP on the well.

Any influx fluid in the cement column will contaminate the cement. This means there may be a flow path causing zonal communication. A large influx may create a gas flow path or liquid flow path to the surface. Remediation will then include cement evaluation logs and a potential cement squeeze. Note that if there is an influx into the cement column, the contamination will be on the wide side of the annulus where the flow is easiest.

7. Lost Circulation

Sign (Observation)

Lost circulation occurs when returns are not coming back to the surface and the fluids are “lost” in the well. Losses may be categorized as partial or complete losses. Partial losses occur when some fluids continue to return to the surface but not at the rates that are pumped in. Complete losses occur when no fluids return to the surface.

Losses can occur prior to cementing or during cementing operations. If lost circulation happens while circulating drilling fluid, then the returns rate will be slower than the pump rate, and the drilling fluids level in the pits will go down.

The hook load may also become excessive in cases of severe lost circulation.

Losses during cementing are a little more difficult to interpret. During a loss of circulation in drilling, the returns rates are slower than they are supposed to be, but during cementing the return rates are typically slightly different from the pump rate because of cement U-tubing. During mixing and pumping of the cement, the returns are typically faster than the pump rate. Returns that match the pump rate are indicative of losses. During the first part of displacement, the returns are typically slower than the pump rate because the pumping is “catching up” to the cement. These slower returns rates are often misinterpreted as losses. If one is trying to assess losses based on the returns rates during cementing, the returns rates must be compared to simulated returns rates rather than the actual pump rates. After the cement job, losses can be evaluated by performing a fluids balance, checking if the total volumes of fluids (including all spacers, slurries, and displacement fluids) return match the total volumes of fluids pumped. If the total volumes returned are less than the total pumped, then losses have occurred during the cement job.

Cause

There are academic books dedicated to lost circulation. Joseph Messenger published an excellent book on lost circulation and treating lost circulation (1981). Lost circulation is also typically a significant chapter in many drilling fluids texts and manuals.

When the pressure in the annulus exceeds the fracture pressure of the formation or exceeds the matrix pressure in a high permeability or naturally fractured zone, lost circulation occurs. The fluids will move from higher pressure to lower pressures and enter the fractures in the annulus rather than traveling back up the annulus and returning to the surface. Figure 9 illustrates fluids moving into a natural fracture in the annulus rather than traveling up the casing.

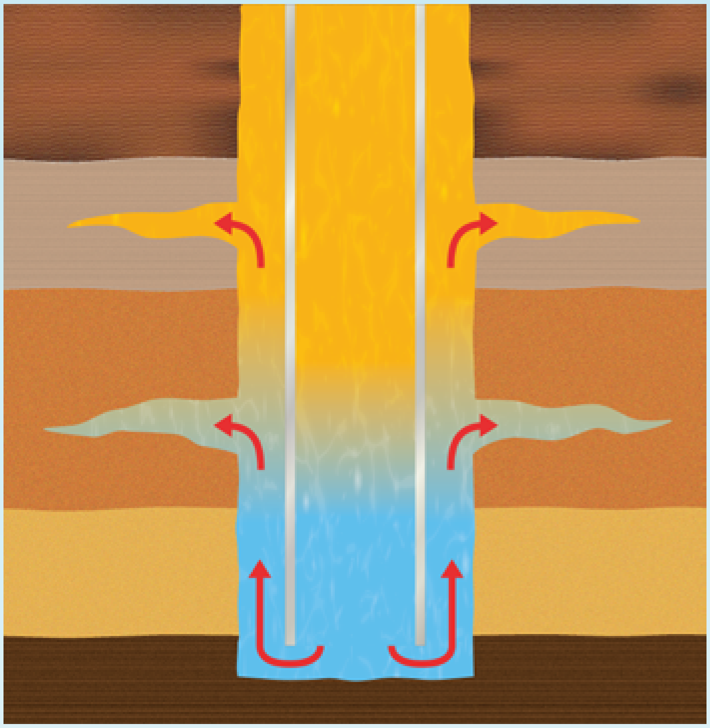

Figure 9: Fluid Losses Into A Natural Fracture In The Annulus

Well designs are inherently at risk of lost circulation due to designs typically pushing the hole section as deep as possible by approaching the formation pressure limits at the previous casing shoe. In addition, cement slurries are typically heavier than the drilling fluids, adding to the downhole pressure and risk of lost circulation. Because of this inherent risk, lost circulation prevention strategies are often included in the drilling fluids program and the cementing program.

Fractures in the formation can accept large volumes of fluids. Thus, if the fracture pressure of the formation is exceeded, a fracture will be created that can accept hundreds of barrels of fluids and result in total loss. When the formation's fracture pressures are exceeded, a fracture will form at the weakest formation in the well. The weakest formation is often at the previous casing shoe but can be at any depth in the annulus. Fractures caused while drilling is called induced fracturing.

The hook load may increase during lost circulation events due to lower fluid levels in the annulus, which provides less buoyancy forces.

Partial losses may occur when fluids are being lost to highly permeable formations or if the pressures are only slightly above the fracture pressure. The pressure in the wellbore pushes some fluids into the formation but is still sufficient to push some of the annular fluids back to the surface.

Lost circulation due to ballooning is particularly challenging. This typically occurs if the pump pressure is sufficient enough to feed the fluid into the induced fracture. However, when the pumps are turned off, the fracture itself can feed fluid back into the annulus as it closes, resulting in a wellbore influx. See Section 6 (page 21) for a discussion on influx.

Pre-Cement Job Prevention

Lost circulation is best managed by including a lost circulation strategy in the drilling fluids program and cementing program.

Drilling fluids programs typically employ several strategies for lost circulation, including managing the drilling fluid density and adding lost circulation material (LCM). There are many types of lost circulation material including a variety of low-density-sized particles, organic and inorganic fibrous materials. Drilling fluid manuals may be consulted for lost circulation strategies.

The cementing program should also consider the risk of lost circulation. A hydraulics simulator such as CEMPRO+ is an essential aid for designing slurry densities and pump rates that maintain downhole pressures between the fracture and pore pressures of the formation. The computer simulation is particularly useful for designing pump rates to minimize the risk of lost circulation.

The spacer and slurry design can also be optimized for potential lost circulation. LCM may be programmed for either or both spacer and slurry. Low-density cement can be deployed to minimize the downhole pressures. Low-density optimized particle size slurries or foam cement are also effective options.

Casing equipment and stage tools may also be deployed to mitigate the effects of lost circulation.

Ideally the well will have the lost circulation solved before cementing operations. The well should be full of fluid and the fluid level should not be dropping. If losses are occurring during the pre-job circulation, the lost circulation mitigation plan included in the cement program is expected to handle the issue effectively.

Mitigation During the Cement Job

Pumping the fluids at the correct densities and adhering to the programmed pump rates during a cement job is crucial to avoiding lost circulation. Programmed LCM are to be added to the cement should the project anticipate losses.

If managed pressure equipment is used, mitigating the risk of lost circulation also requires that the programmed schedule for the choke be followed.

In the case that real-time monitoring is available and can be compared to a real-time simulation, pump pressures and returns may be monitored in real-time to assess if losses are occurring. Pump rates may be reduced within the tolerance of the cement program to minimize the losses.

Remediation

Loss circulation events typically result in a low top of cement (TOC) and will be discussed in Section 11 (page 37). CEMPRO+ includes a Lost Circulation Module that is useful for understanding where the TOC could be if there is lost circulation during the job and if there are partial or complete losses.

Once the TOC is determined (through simulation, volume analysis, and simulation analysis), it can be determined if a cement squeeze is necessary to raise the TOC. The well can be perforated at the top of the cement and sufficient cement can be circulated into the annulus to raise the top of the cement to the required level.

8. Poor Pumpability (Excessive Pressure)

Sign (Observation)

High pump pressures during cementing indicate poor pumpability.

Figure 10 indicates a pressure gauge showing higher pressure than anticipated. Note that high pressure is not an absolute observation, and the pressure should be compared to the simulated pressure before making any conclusions. Many cement jobs are pumped at anticipated pressures of 5000 psi while other cement jobs observed with poor pumpability have pressures as low as 1000 psi.

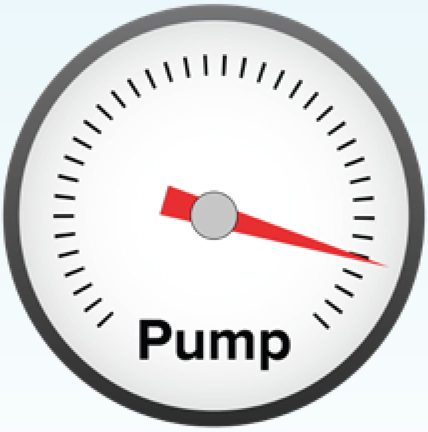

Figure 10: High Pumping Pressure

Cause

The cause of the high pressures can be attributed to something in the wellbore or to the cementing fluids.

Restricted or blocked flow paths often immediately result in high pressures. This blockage can be due to casing stretch, restrictions in the wellbore, cuttings bridging, or early cement setting.

During cementing, the casing typically stretches slightly. If the casing is placed too close to the well's bottom, it is possible to stretch the casing into the well's bottom and plug the casing's bottom.

A restricted annulus flow path will increase the pumping pressure. If there are cuttings in the well, they may be circulated up and they can bridge at any restriction in the annulus, especially liner hangers, but potentially on centralizers or any other casing equipment in the annulus. If there is LCM[1] in the drilling fluid or any of the cementing fluids, it can also bridge on the float equipment in the casing or the annulus. It should be noted that the rheology interfaces at the spacer and cement slurry can be efficient in picking up cuttings or LCM[1] that may be in the wellbore.

The cement slurry itself can also cause pressure increases. If the slurry loses fluid to the formation, the increased density and increased solids content will increase the viscosity of the slurry and pump pressure. Under severe cases, the cement slurry can set prematurely, effectively blocking the flow where the cement has set.

Contamination of incompatible fluids in the well can also cause increased pumping pressure. Incompatible fluids will have significantly higher viscosity, which will appear as increased pump pressure.

Pre-Cement Job Prevention

The best prevention is to have a good casing design, mud removal plan, and good slurry design, and representative simulation.

Casing stretch can easily be planned for by using a computer simulation such as CEMPRO+ to understand how much the stretch will be. The rathole length should be sufficient and the casing landed shallow enough that the casing cannot stretch into the bottom of the hole.

The wellbore should be circulated clean before the commencement of cementing operations. Any cuttings left in the wellbore have the potential to bridge off the annulus.

---

[1] Lost circulation material

LCM[1] concentrations should be designed to pass through the casing equipment and annulus. Low levels of LCM[1] are common during cementing operations, but large concentrations of LCM[1] can tend to bridge at annular restriction.

A good cement slurry design is critical. Lab tests at simulated well conditions will mitigate the risk of the premature cement setting. Fluid loss control will maintain the fluid in the slurry so that the rheological properties are constant. API[2] 10B-2 describes all industry-accepted methods for testing cement slurries in the lab. The program CEMPRO+ predicts the pressure and temperature schedules that should be used for the lab tests.

Compatibility testing for all fluid interfaces will also reduce the risk of increased rheology and pressure due to incompatible fluids. Bottom plugs may also separate fluids and minimize the mixing of mud, spacer, and cement. A computer simulation helps understand how much the fluids will be mixed, especially considering the long horizontal wells of today. A compatibility test schedule ensures that all fluids are compatible.

Mitigation During the Cement Job

The primary mitigation for poor pumpability is to mix and pump the fluids at the designed density and prescribed pump rates.

In the case that high pressures are encountered during cementing, there are not many tools available at the well site. The pump rate can be reduced to keep the pressures within the operating limits of the wellbore. In cases of annular bridging, the pressure may drop if the bridge lets go.

Under the suspicion that the casing stretched into the bottom of the wellbore, stop pumping and lift the casing by several feet. Once the casing is off the bottom the pressure will drop and pumping will resume.

Remediation

If the job is pumped to the end and the plug bumped, then remediation is likely unnecessary.

In the event where the job ends before the plug is bumped, then remediation may be necessary. At the very least, the inside of the casing will have to be drilled out to start the next operation.

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[1] Lost circulation material
[2] American Petroleum Institute

Where the job ends is important for deciding remediation steps. The TOC will need to be determined on a volumetric basis. If there are also losses, then a cement evaluation log may need to be run to determine the top of the cement. If the TOC meets the well requirements, then no remediation is required. If the TOC is lower than required, the cement top will have to be raised by perforating, circulating, and squeezing cement in.

9. Wet Shoe Track (After Placement)

Sign (Observation)

The first sign of a wet shoe is often the inability to get a pressure test after the cement job. Repeatedly failed pressure tests may push more displacement fluid into the annulus.

Another early indicator of a wet shoe is the inability to achieve a formation integrity test (FIT) or leak-off test (LOT). A failed LOT or FIT may occur for reasons other than a wet shoe, but a wet shoe can lead to a failed LOT or FIT.

A pressure decrease at the end of displacement also indicates the possibility of a wet shoe as the lighter displacement fluid enters the annulus. This small decrease in pressure is often more noticeable when analyzing the digital record than it is when observing the pressure in real-time.

Another cause of a wet shoe is when the displacement volume pumped exceeds the calculated casing volume and the volume of the float collar. A wet shoe typically consists of a small volume of displacement fluid entering the annulus. Accounting for small volumes associated with compressibility, casing ID variation from casing manufacturing, pump efficiency, and well site measurement accuracies may be inconclusive in determining over displacement. Occasionally, an operational error will result in a large over displacement volume being pumped, resulting in a wet shoe.

A wet shoe may also result in unexpected drilling problems when drilling out the shoe track. The plug may spin on the landing collar, caving may fall in on the bit from outside the shoe. In the worst case, the shoe joint can be unscrewed from the casing string. A failed LOT or FIT may also require additional casing strings or a change in the program for the next section. High cost for fixing wet shoe track is a reason why such problems should be avoided.

Wet shoe on the production casing string is often followed by zonal communication of unwanted water or gas.

[1] Top of cement

Acoustic cement evaluation run in a well can help evaluate the cement bond near the shoe. Cement evaluation logs can help determine the extent of a wet shoe.

Cause

A wet shoe is caused by displacement fluid entering the annulus at the end of displacement. Figure 11 shows the displacement fluid in the annulus.

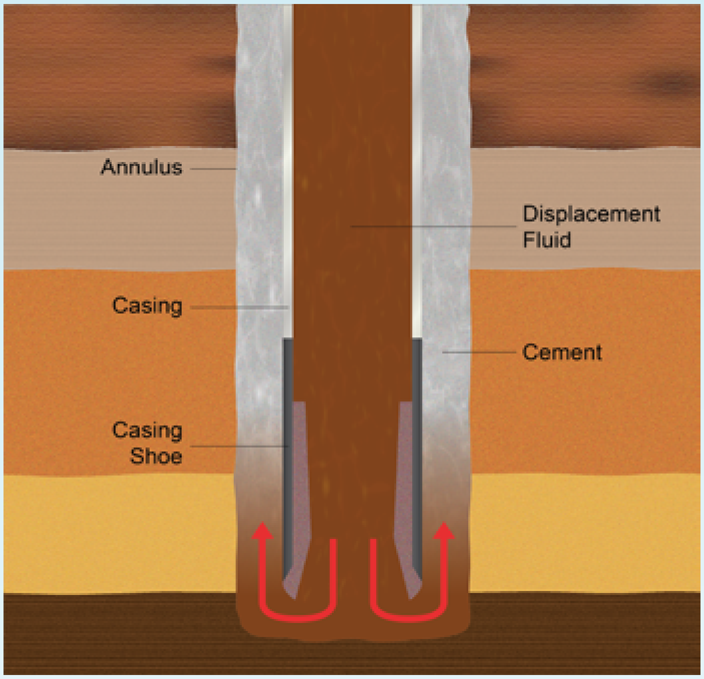

Figure 11: Displacement Fluid Entering The Annulus Causing A Wet Shoe

The displacement fluid enters the annulus when the volume pumped is greater than the casing capacity. Although intuitive, small volumes caused by displacement fluid compressibility, casing ID tolerances from manufacturing, pump efficiencies, well site measurement accuracy, and mud film wiped by the plug can add enough volume to the displacement fluid to cause a wet shoe.

A failed casing pressure test can also add displacement fluid to the annulus, particularly if the test is attempted several times and the pressure test fluids are not bled off to the surface.

The displacement fluid in the annulus can create a communication path to shallower zones, which explains failed FIT[1], LOT[2], or production of unwanted water or gas.

Fluid migrating up from the rathole after cementing is another low probability cause of a wet shoe.

[1] Formation integrity test
[2] Leak-off test

Pre-Cement Job Prevention

The primary method for preventing a wet shoe is to ensure that the displacement volume is calculated ahead of time and a maximum volume is set. Most operators will choose a maximum volume that includes the volume of half of the shoe track below the landing collar. This volume will allow and account for some compressibility or pump efficiency variation.

Compressibility of the displacement fluid may be accounted for in calculating the displacement volume. The volume associated with compressibility is particularly important for deepwater wells when non-aqueous fluids are used for displacement. The compressibility of the fluid may add up to 2% in the displacement volume that could be tens of barrels.

A longer shoe track may be deployed in the well to minimize the risk of a wet shoe. The shoe track collects the film of mud that is wiped by the wiper plug during displacement. A film of a few thousandths of an inch can add up to more than a barrel, especially for larger casings. A longer shoe track can tolerate contaminated cement just below the landing collar with uncontaminated and strong cement still at the shoe.

Sometimes a wet shoe is designed into the well. The completion program for a long horizontal well may include a first stimulation or fracturing stage that will be pumped out the shoe of the production casing. In these cases, displacement fluid may be pumped before the plug and retarded water (sometimes retarded with sugar) may be pumped behind the top plug. A wet shoe is required to be able to complete the well.

Mitigation During the Cement Job

Over displacement and a wet shoe can be prevented by requiring accurate volume measurement at the well site and maximum displacement volume that is not exceeded before the job.

Accurate volume measurement is a must. Mass flow meters such as Coriolis meters are quite accurate. Displacement tanks can be monitored. Pump stroke counters are also useful. Note that pump stroke counters count the strokes rather than the actual volume of fluid pumped. The accuracy may be affected by pump efficiency, how the pump is primed, and the mechanical condition of the pump.

Do not over-displace. Some operations employ a method called “pump till you bump” which increases the risk of over displacement. This method minimizes the risk of cement left inside the casing but increases the risk of over displacement.

Minimize any volumes that are pumped after bumping the plug. Sometimes the casing is pressure tested on plug bump. In this case, the pressure should be bled off back to the surface. If the test fails, it should not be repeated until after the cement sets. If the plug fails to bump, a plug bump should not be reattempted.

Remediation

A wet shoe can cause significant problems in subsequent well operations and should be repaired. Typically, a wet shoe is repaired by performing a cement squeeze at the shoe.

10. Lifted Casing (During Pumping)

Sign (Observation)

The casing rising out of the hole, the slips, or lifting off the elevators is a sign of lifted casing, posing a significant safety risk on the rig floor. Casing lifting occurs while the pumps are engaged.

Casing lifting is a significant safety risk on the rig floor. Casing lifting is a significant risk on the rig floor because the lifted casing can bang into the hook or other equipment on the rig floor.

Another indication on the driller's console is if the casing is hanging in the elevators, the weight indicator goes to zero.

Cause

Casing is lifted out of the ground due to buoyancy and pressure forces being larger than the weight of the casing. Casing lifting is typically a risk for shallow, large-diameter casing strings where the pressures acting on the casing area can overcome the weight of the casing.

Both buoyancy and pump pressures contribute to lifting casing. Figure 12 illustrates the forces acting at the bottom of the casing to lift the casing. A simulator such as CEMPRO+ can be used to predict the buoyancy forces and pressure forces during the cement job so that the risk of lifting the casing can be assessed.

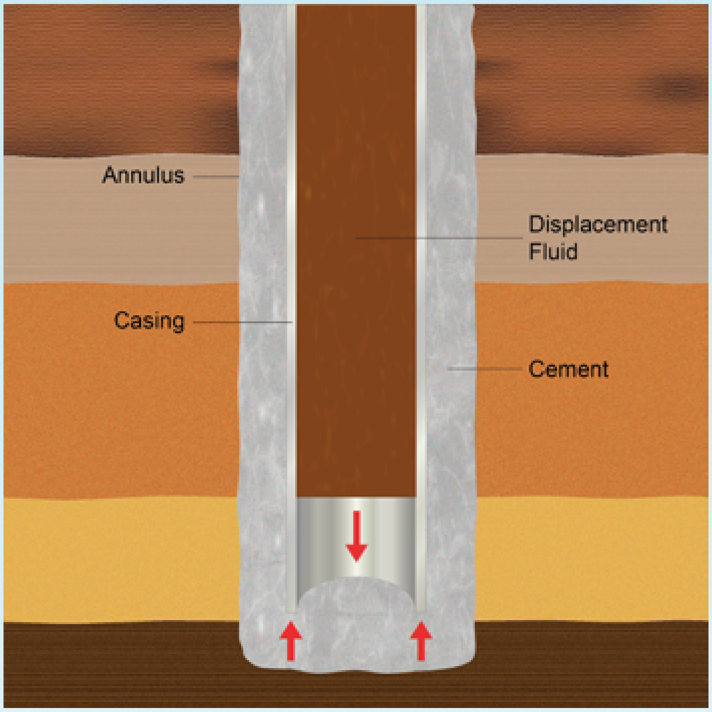

Figure 12: Buoyancy And Pressure Forces Acting On The Casing

Buoyancy forces are a contributing factor for casing lift. Buoyancy forces are typically at its greatest at the end of the cement job where the higher density cement is in the annulus and lower density displacement fluid is in the casing.

Pump pressures also contribute to the forces that lift the casing out of the hole. Pump pressure due to the friction of the fluids in the annulus can contribute to hundreds of pounds of lifting force. Any restriction in the annulus such as cuttings bridging will contribute to casing lift by increasing pump pressures.

Pre-Cement Job Prevention

The primary method of preventing casing lifting is to be prepared for it. This is especially true for large diameter shallow strings or several more joints (up to 10) of larger casing sizes. A casing lift pressure calculation should be performed prior to each cement job to assess how much surface pressure will lift the casing at the end of displacement. This calculation may be done by hand or by a cementing simulator.

Using the hook load prediction of a cementing simulator such as CEMPRO+ can also help assess the magnitude of the lifting forces. The simulator also helps assess the lifting force reduction associated with reducing the cement slurry density or increasing the displacement fluid density.

If casing lifting is assessed as a risk, the casing can be tied down with chains to the rig floor. Note that chains can provide several hundred pounds of hold-down force. But if the lifting forces exceed the strength of the chains, the chains will break.

The hydraulics simulations for cementing should also be performed to determine the safe pumping rate that will minimize the risk of lifting the casing.

Mitigation During the Cement Job

The best method to preventing or minimizing casing lift during the cement job is to slow down the pump rate. Slowing the pump rate will reduce the friction forces in the annulus and the pressures acting at the bottom of the casing that lifts the casing. If the tie-down chains become too tight, the pump rate should be reduced. If the casing is lifting out of the ground, slow the pump rate sufficiently to allow the casing to drop again. The pump rate can be reduced to zero (stopped) to allow the casing to drop back in the ground.

If there are large cuttings coming out of the hole prior to shallow casing cementing, the operator should be prepared for casing lifting. The cuttings can bridge and cause extra lift pressures.

Remediation

If the casing is lifted, then it may not be cemented to the required depth. Ideally, the casing will fall back to desired landing depth with reduced pump rates or no circulation.

If the casing shoe is higher than the desired landing depth at the end of cementing, put weight on the casing to push it down a few feet to the required landing depth before the setting of cement.

If the casing is higher than the required landing point, and the cement has been set, it will not be possible to move the casing. The wellhead will need to be adapted to the new depth and the next hole section drilled from the actual casing depth.

11. Low Top of Cement

Sign (Observation)

The cement top is typically a regulatory requirement, leading to a lot of interest in any signs indicating that there may be a low top of cement (TOC).

A low TOC is usually suspected if some other problems such as lost circulation or loss of returns occurs during cementing. Other indicators such as low final cementing pressures or hook loads higher than simulated can be other indicators of a possible low TOC.

If the cement slurry volume pumped is less than the programmed or calculated annular volume, a low TOC will result.

The actual TOC should be confirmed with cement evaluation logs, a volumetric analysis, a cementing pressure evaluation, or a combination of these methods. The cement evaluation logs together with the cementing treatment report are reliable methods to observe where the TOC is and determining if it is lower than required.

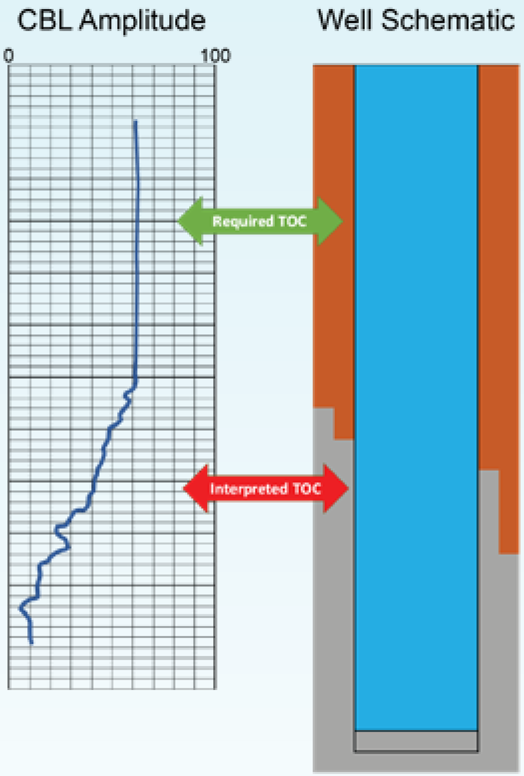

Figure 13: Low Top Of Cement - Cement Evaluation Log And Well Schematic (Credit: Gunnar Debruijn)

Sometimes, when placing cement plugs, the top of the plug or TOC[1] will be lower than planned or required. This is typically determined if the plugs are tagged mechanically with drill pipe or tubing. The cement will not support the drill pipe or tubing at the expected depth. The drill pipe is then lowered to the point where the cement supports the drill pipe. If the weight indicator on the drill floor reduces, then the drill pipe bottom is at the point where the TOC[1] is.

Cause

The simple reason for a low TOC[1] is that the cement volume in the annulus is not sufficient to fill the hole to the required TOC[1].

There are various operational or logistical reasons for small volumes to be pumped, but an insufficient volume of slurry will not fill the hole.

Another common challenge is the that we do not know accurate hole sizes. Cement excess is typically added to the calculated volume to make up for the uncertainty. However, occasionally the hole may be larger than anticipated and the cement volume will not be sufficient to fill the hole to the required height. Conversely, the hole size may be slightly smaller than anticipated and the cement may rise higher in the annulus than expected. Higher cement tops are typically not a problem but can lead to lost circulation.

Lost circulation may result in a low TOC[1] if the loss zone is below the required TOC[1]. Particularly in the case of complete losses, the loss zone may take all the fluids, including the cement slurry, and the cement will not rise above the loss zone. If the annulus bridges and losses occur, the TOC[1] may not be achieved above the bridge.

A premature end to the cement job can also cause a low TOC[1]. Regardless of the causes of a premature end of the cement job (operational mechanical problems, bridging in the annulus, lost circulation, premature cement set), the reason for the failure of achieving the desired TOC[1] is insufficient volume of slurry to be placed in the annulus.

Contamination at the top of the cement slurry will also contribute to low TOC[1]. If the lead edge of the cement is significantly contaminated with drilling fluid or spacer, it may not develop sufficient strength to be interpreted as cement in cement evaluation logs.

[1] Top of cement

Contamination of cement at the top of a cement plug is a common problem. The leading edge and trailing edge of the cement mixes with the other fluids in the wellbore while traveling down the pipe and up the annulus. The cement is additionally contaminated as the pipe is pulled out of the plug. Small cement slurry volumes associated with cement plugs can be completely contaminated with spacer, drilling fluid, or both.

Pre-Cement Job Prevention

The cement job planning and designing stages are the best time to ensure a desirable TOC[1]. This means that the program should include a good centralization program, a good mud removal plan, a good slurry design, and representative simulations for the cement job. It also means that well parameters should be communicated between all the parties involved in the cement job so that they can be incorporated in the cementing plan.

When planning cement plugs, a computer simulation like PlugPRO is useful for understanding the possible contamination of the cement and adjusting the cement program to minimize the risk of cement contamination.

Mitigation During the Cement Job

Mixing and pumping fluids at the designed density and prescribed pump rates should help jobs avoid low TOC[1].

If lost circulation is anticipated, make early preparation to mitigate it.

A minimum volume of cement slurry should be determined and contingency plans may be developed in case the minimum volume is not met. For example, if mixing is stopped prior to the minimum cement volume is met, the cement can be circulated out of the hole and the job repeated.

Remediation

Remediation for low TOC[1] is typically prescribed by regulations given that it is a requirement.

In the USA Code of Federal Regulations (CFR), the regulation prescribes in CFR 250.428 that if you “[h]ave indication of inadequate cement job (such as lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment). Then you must:

[1] Top of cement

1. Locate the TOC[1] by:
   i. Running a temperature survey; or
   ii. Running a cement evaluation log; or
   iii. Using a combination of these techniques
2. Determine if your cement job is inadequate. If your cement job is determined to be inadequate, then you must refer to paragraph [take remedial action].
3. If your cement job is determined to be adequate, report the results…"

The remediation for an inadequate cement job requires that the TOC[1] is determined and then a remedial plan be developed and approved.

Raising the TOC[1] can be done by performing a cement squeeze and circulating more cement into the annulus. If a cement plug has a low top, a subsequent cement plug can be set on top of the first plug. The drilling program may also be modified to take into account the low TOC[1].

IV. Conclusion

Many common cementing problems occur at the well site. The cement may account for gas flow (after cement placement), zonal communication, stimulation communication between stages, poor displacement efficiency, cement failure, fluid influx (during pumping), lost circulation, poor pumpability, wet shoe track, lifted casing (during pumping), and low top of cement (annulus). However, drilling issues or well design components such as drilling fluids program, and casing centralization have their own fair share of causes of these common cementing problems.

Common cementing problems can generally be avoided by proper planning and preparation for the cement job. This includes mitigation strategies in the cement program and installing the cement according to the program. The cement program should consist of a centralization program, a good mud removal plan, a good slurry design, and a representative simulation of the cement job using a simulation such as CEMPRO+.

Finally, the cement job should be executed according to the program. This means pumping fluids in the correct order, pumping the programmed volume, mixing fluids at the specified pump rates, and keeping the pump rates within the programmed tolerance.

Remedial cementing involves cement evaluation and a cement squeeze. With proper planning and execution of the primary cement job, costly remedial cementing jobs can be avoided.

1 Top of cement

To learn more about CEMPRO+ or any other drilling software, please visit Pegasus Vertex, Inc. (PVI) website at www.pvisoftware.com. For more information, please contact PVI at:

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www.pvisoftware.com

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