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Review of Critical Factors That Affect Cement Slurry Design for Oil And Gas Wells

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Abstract
Construction of oil and gas wells involves several complex processes, that include site preparation, hole drilling, running casing, cementing, and well completion. The various stages are carefully designed and executed to safely and efficiently access subsurface hydrocarbon reservoir. The wells may be drilled vertically, directionally or horizontally into the reservoir, either offshore or onshore. The wells may also be unilateral, multilateral, extended reach or side-tracked. The configuration of the well depends on a lot of factors, which include purpose of the well, characteristics of the reservoir and geological conditions. The key objective of oilwell cementing is to isolate various zones, support and protect the casing and create a safe conduit for fluids to flow in the well. Cement slurry design is a critical element in achieving effective zonal isolation and structural support for oil and gas wells. This paper reviews the core factors that affect cement slurry designs and their impact on slurry properties. Some of these factors include well location, topology or rock properties, wellbore geometry, wellbore conditions, fluids compatibility, and available technology. For effective job design, equipment, slurry type, slurry weight, and additives must be carefully selected to match the well conditions and to meet the job objectives. It is recommended for laboratory tests be conducted at simulated downhole conditions for cement slurry validation before the job execution. A cementing job can be said to be successful if a competent cement seal is created to provide a dependable hydraulic seal throughout the life span of the well.
Key Words: *Drilling, Cementing, Completions, Production, Slurry, Wellbore, Additives.*

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I. Introduction

Construction of hydrocarbon wells involves complex processes, carefully designed and engineered to safely and efficiently access the sub-surface reservoir, with minimal cost. These processes include exploration, site preparation, drilling, cementing, and completion. Exploration and site preparation involves geological studies, seismic surveys, data analysis, permit / authorization from government regulator, site construction, and mobilization of the rig to site (Economides, *et al*. 1998).

Well Plans often include various stages such as prospect development, data collection, pore pressure evaluation, fracture gradient prediction, pipe setting depth selection, bit program, hole geometry, completion planning, drilling or mud plan, cementing plan, casing plan, tubing design, drill staring design, rig selection, drilling projection and cost estimation (Adams, 1985).

Oil and gas wells can be classified into various types, mainly based on functions, and this include wildcats, exploration, step-outs, infills, appraisals, reentries, production, injection, waste disposal and relief wells (Adams, 1985). Wells can be unilateral and multilateral and can be drilled vertically, directionally deviated, and horizontally into the reservoir for various reasons, which include accessing other adjacent reservoirs, side tracking to avoid obstacles, higher production rates or some other economic reasons (Economides, et al. 1998). Vertical wells are drilled directly straight down into the reservoir below and are usually used for shallow wells and associated with low cost. Directional drilling involves drilling at angle to access the reservoir not directly below the drilling rig. Horizontal drilling is used to maximize the length of the wellbore exposed to the reservoir, especially for thin or tight wells, thereby increasing the production rate and very useful in extraction of hydrocarbon from shale. Multilateral wells involve multiple branches from one main borehole (Economides, et.al. 1998).

In oil and gas well construction, cementing the casing to the surrounding formation is fundamental to well performance over its lifecycle. The cement sheath provides zonal isolation, supports the casing string, prevents fluid migration, seals off lost circulation zones, and protects against corrosion, shock loads and external pressures (Stiles, 2012). Poor slurry design can lead to well failure, reduced production, and environmental hazards due to inadequate seals or channeling within the annulus (Renpu, 2011).

Drilling fluid is usually circulated in the borehole during drilling operations to transport the drill cuttings, for pressure control by providing sufficient hydrostatic pressure to balance the pore pressure, provide bore hole stabilization, minimizes damage to the production formation, to cool and lubricate the drill bits and allows information about the formation to be retrieved through cuttings analysis, wireline logging and logging while drilling (Smith and Ravi, 1991). Drilling fluid selection is one of the most important criteria for successful well construction. Drilling fluids can be classified into Water-based (fresh or saline), Oil-based, Synthetic-based and Pneumatic (air, mist, foam, gas) fluids systems (World Oil, 2012). Water-based fluids (WBF) are the most used and less expensive than Oil-based fluids (OBF) or Synthetic-based fluids (SBF), which are usually used when the formation properties require reliable shale inhibition and good lubricity. Pneumatic fluid systems are normally used to prevent formation damage or lost circulation in areas with low formation pressure (Smith, 1990). Drilling fluids usually contains additives to improve their properties. Drilling fluids additives include bactericides, pH control, hardness control, viscosifiers, fluid loss control, dispersant, defoamers, corrosion inhibitors, emulsifiers, flocculants, Loss Circulation Materials (LCM), lubricants, weighting agents, shale control inhibitors and others (Smith and Ravi, 1991).

Cementing operations can be divided into primary and secondary. Primary cementing involves mixing cement, water and additives and pumping it downhole, usually through the casing to the annulus to bond and support the casing. Secondary or remedial cementing is usually utilized to repair or correct problems associated with primary cementing jobs such as plugs and squeeze jobs. (Stiles, 2012). Thorough planning, designing and execution of primary cementing can eliminate the need for remedial jobs. Cement slurries can be designed and tailored to the specific requirements of the downhole conditions and to meet the job objectives (Smith, 1990)

The depth of running casing and cementing is chosen based on formation pressure, fracture gradient and geological reasons, to allow the well to be drilled safely and economically (Adams, 1985). There are various types of casing strings, which include: Structural or Drive, Conductor, Surface, Intermediate, Liners, Production, and Tubings. Conductor casing is usually the first string to be placed in, usually up to a depth of 100 – 300 ft in soft rock area (Adams, 1985). Structural casing may be run between the drive pipe from a depth of 600 – 1,000 ft, depending on geological or job demand. Surface casing is often run to cover freshwater sands and weak zones, uphold hole integrity, base to attach Blow Out Preventer (BOP), prevent lost circulation into shallow permeable zones and support the entire casing strings (Bourgoyne *et al*., 1991). Intermediate casing is primarily used to protect shallow weak formation from abnormal formation pressure and isolate salt zones or zones with sloughing shales. Liners are run from the previous casing, instead from surface and used for the same purpose as intermediate casing and for fracture gradient control or to control pressure economically. Production casing or the oil string is used to isolate the production zone and protect sub-surface and tubing equipment (Smith, 1990).

The ability to simulate downhole conditions and optimize fluid design will help to reduce nonproductive time, real-time management of hole conditions through data feed from downhole tools allows the operator and fluid specialist to fine-tune drilling parameters. (Smith, 1990).

II. Cement Slurry Design

Understanding the key factors that affect cement slurry design and how they impact cement slurry properties and other variables enables engineers to tailor cement formulations that can be appropriate for specific geological and operational demands, thereby enhancing well integrity and safety. Economides, et. (1998) noted that the following factors influence cement slurry designs:

2.1 Slurry Physical Properties

Cement slurries must be formulated to possess required physical properties to enable them to perform adequately at the downhole conditions and meet the job design and job objectives.

The performance of a cement slurry depends heavily on the correct selection and concentration of additives. Cememt additives include Accelerators, Retarders, Dispersants, Fluid-loss control agents, Light weight agents, Heavy weight agents, Suspension aids, Anti-gas migration, Anti-foaming, and others (Nelson, et al., 1993). Improper additive design may lead to inadequate slurry placement and job failure (Taylor, 1997; Scrivener and Nonat, 2011).

Cement slurry physical properties include weight or Density, Rheology, Thickening time, Free fluid, Fluid loss, Compressive strength, Sedimentation, Anti-gas migration, Elasticity, Expansion and others. The required property depends on the downhole condition and job objectives (Nelson, et al., 1993).

2.1.1 Slurry Density

Slurry density must be carefully selected to perform the following:

- Provide adequate hydrostatic pressure to balance formation pore pressure to control formation fluids influx into the wellbore. The formation pressure must be lower than the fracture gradient of the formation to avoid fracturing weak formations that may cause loss circulation.
- Maintain wellbore stability

Density is controlled by the water-to-cement ratio and the use of light weight or heavy weight additives. Light weight additives include Bentonite, Sodium silicate, Hollow Glass Spheres, Ceramic beads. Heavy weight additives include Barite and Hematite (Smith, 1990). The water-to-cement ratio directly affects slurry yield, rheology, pumpability, permeability and compressive strength. Higher water ratios increase fluidity, porosity but can lower compressive strength and increase the risk of high free fluid, settling and channeling (Nelson, 1990).

Table 1: Typical Cement Slurry Density Ranges (Nelson, 1990)

Well Condition	Density (ppg)	Typical Application
Fragile formation	9.0 - 12.9	Lightweight system
Shallow wells	11.5 - 13.5	Surface casing
Normal pressure	14.8 - 16.4	Intermediate casing
High pressure	16.5 - 19.5	Deep producing casing

Nelson (1990) noted that Hydrostatic pressure exerted by the cement column is calculated as follows:

$$P_h = 0.052 \times \rho_c \times D \qquad (1)$$

Where:
P_h= hydrostatic pressure (psi)
ρ_c= slurry density (ppg)
D= true vertical depth (ft)

2.1.2 Rheology

Rheology of cement slurry indicates its flow behaviour, pumpability, pressure losses and mud displacement efficiency. Key rheological parameters include Plastic Viscosity (PV), Yield Point (YP), and Gel Strength. (Bourgoyne et al., 1991; Lake & Mitchell, 2006).

Cement slurries are non-Newtonian fluids, which shear stress is not directly proportional to shear rate. Several models can be used to describe non-Newtonian fluids, including the Bigham plastic, Power law, and Herschel models (Annis and Smith, 1996; API, 2013). No single model can completely describe the behaviour of non-Newtonian fluid across the entire range of shear rates (API, 2013). Rheology is determined using a rotational viscometer.

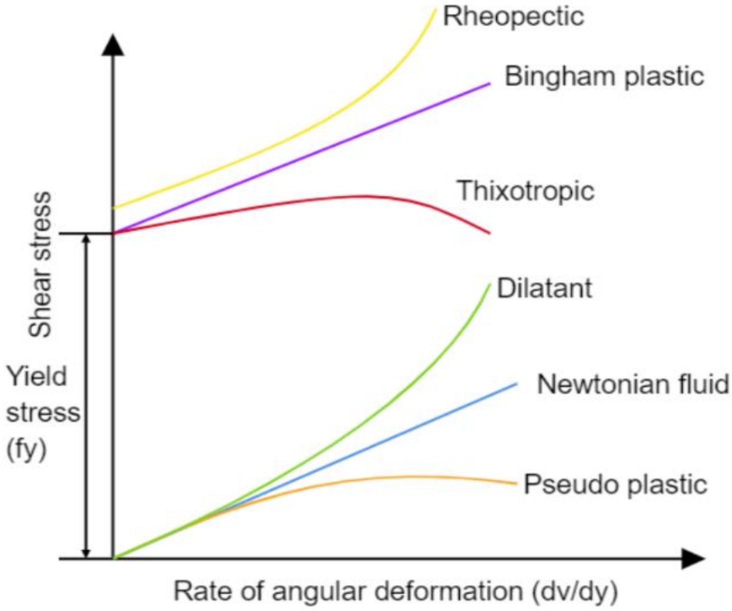

Figure 1: Plots of Newtonian and Non-Newtonian Fluids (Elkington, 2023)

API (2013) described various mathematic models of describing Newtonian and various non-Newtonian fluids behaviour. The Bingham Plastic model is expressed as follows:

$$\tau = \tau_y + \mu_p \dot{\gamma} \qquad (2)$$

Where:
τ= shear stress (lbf/100ft^2)
τ_y= yield stress (lbf/100ft^2)

μ_p= plastic viscosity (cP)
$\dot{\gamma}$= shear rate (s^{-1})
Plastic viscosity and yield point are calculated as:

$$PV - (\theta_{300} - \theta_{100}) \times 0.5 \qquad (3)$$

$$YP = \theta_{300} - PV \qquad (4)$$

Where:
PV = Plastic Viscosity in cP
YP = Yield Point in lbf/100ft^2
$\theta_{300}, \theta_{100}$= viscometer dial readings at 300rpm and 100rpm respectively

Power law model is described as follows:

$$\tau = k\,\gamma^n \qquad (5)$$

Where,
τ= shear stress (lbf/100ft^2)
γ = shear rate (s^{-1})
k = Consistency index (lbf.s^n/100)
n = power law flow behaviour index

Herschel-Bulkley model combines part of Bingham Plastic model with part of Power law, and can be described as follows:

$$\tau = \tau_y + k\,\gamma^n \qquad (6)$$

Where,
τ= shear stress (lbf/100ft^2)
γ = shear rate (s^{-1})
τ_y= Herschel-Bulkley yield stress (lbf/100ft^2)
n = Herschel-Bulkley flow behaviour index
γ = shear rate (s^{-1})

These parameters are essential for predicting pump pressures and annular flow behavior and other hydraulics (Annis and Smith, 1996; De Andrade, J., and Kelessidis, 2016).

2.1.3 Thickening Time

Thickening time (TT) is the period during which the slurry remains pumpable under simulated downhole condition. According to API (2013), slurry is considered set or pumped off when the consistency gets to the value where it is deemed unpumpable (usually 70 or 100 Bearden Consistency Units (Bc)). Retarders or accelerators are added to the cement slurry to obtain the required TT depending on the temperature and operational requirements (Plank and Hirsch, 2007). It is measured using a high pressure, high temperature (HPHT) consistometer.
Nelson and Guilollot (2006) mentioned that TT can be modelled using temperature-dependent reaction kinetics, expressed by Arrhenius-based model as follows:

$$TT = A\exp\left(\frac{E_a}{RT}\right) \qquad (7)$$

Where:
TT = Thickening time (min)
A= Pre-exponential factor (empirical constant)
E_a= Activation energy of cement hydration (J/mol)
R= Universal gas constant (8.314 J/mol·K)
T= Absolute temperature (K)
This shows that as temperature increases, thickening time decreases exponentially and Retarders increase the apparent activation energy E_a, there by extending pump time (Nelson and Guillot, 2006).

2.1.4 Free Fluid

Free fluid is associated with separation of supernatant fluids and settling of solid particles in the cement slurry, indicating slurry instability, which can cause top-of-cement contamination, density gradient in the fluid, and compromise the success of the cementing operations, especially in deviated and horizontal wells (Smith, 1990). Therefore, cement slurries must be designed to exhibit minimal free water in accordance with the job design and adequate suspension stability (API, 2010).

Free fluid is calculated as follows

$$\varphi = \frac{V_F\ (100)}{V_s} \qquad (8)$$

Where,

φ = Free fluid (%)
V_F = Volume of free fluid (ml)
V_S = Initial volume of slurry (ml)

2.1.4 Fluid Loss

Fluid loss refers to the filtration of fluid from the cement slurry into the formation under differential pressure. Excessive fluid loss can cause premature dehydration, poor cement bonding, and increased permeability and tendency of gas migration (Nelson & Guillot, 2006).

Fluid loss is measured using an API HPHT filter press at a pressure differential of 1,000 psi, and calculated as follows (API, 2013):

$$FL_{API} = 2V_{30} \qquad (9)$$

$$Calculated\ FL_{API} = 10.954\ x\ \frac{V_f}{t^{0.5}} \qquad (10)$$

Where:

V30= volume of filtrate collected at 30 min
V_f= filtrate volume (mL) collected at time t
t= time (minutes)

Fluid-loss additives are incorporated into the cement slurry to reduce fluid loss in accordance with the design specification and maintain the slurry integrity, particularly in permeable formations. Recommended fluid loss depends on the well conditions and job type (Smith, 1990).

2.1.5 Compressive Strength

Compressive strength indicated the mechanical and structural integrity of the set cement. The cement slurry is required to develop sufficient compressive strength within a reasonable time, called “Wait-on-Cement” to allow continuation of the drilling operations, support the casing loads and withstand thermal and mechanical stress (Smith, 1990). The compressive strength development depends on the class of cement, water content or slurry weight, temperature, and additives (Nelson & Guillot, 2006). Compressive strength development is measured, either by mechanical crush testing of cement cubes or electronically with Ultrasonic Cement Analyzer (API, 2013).

2.1.6 Gas Migration

Gas Migration test measures the ability of a cement slurry to resist fluid (gas or water) flow under static conditions. This is validated by combination tests which include Static Gel Strength (SGS) development, Zero Gel Time (ZGT), Transition Time, Shrinkage/Expansion, permeability and Gas flow simulations (Suton, et al. 1989). In gas-bearing formations, cement slurry design must have low transition time and maintain sufficient hydrostatic pressure to prevent gas influx. Static gel strength testing evaluates the transition period of the cement slurry from fluid to solid states, which is critical for gas migration control. Specialized additives, low fluid loss and optimized rheology are often required (Nelson & Guillot, 2006).

API (2013) noted that the critical transition time is the interval between 100 and 500 lbf/100 ft² gel strength. This is critical for gas migration control and can be expressed as follows:

$$t_{tr} = t_{500} - t_{100} \qquad (11)$$

Where:

t_{tr}= Transition time (min)
t_{100}= Time to reach 100 lbf/100 ft² gel strength
t_{500}= Time to reach 500 lbf/100 ft² gel strength

Short transition time reduces the risk of gas migration during setting of the cement slurry. It is recommended to have a transition time of not more than 45 minutes for effective gas migration control (API, 2013).

2.2 Well Downhole Conditions and Geometry

The well condition and its geometry significantly dictate the design of cement slurry formulations. Downhole conditions such as temperature and pressure increase with depth. Therefore, the depth of the well significantly dictates the temperature and pressure that the cement slurry will encounter. (Economides, 1998). High downhole temperature generally increases reaction rates, accelerate slurry hydration, reduces thickening time and increases the likelihood of premature gelation in some formulations, while high pressure influences fluid loss and slurry instability (Ahmed, 2019).

Cement slurry placement occurs under dynamic mode, therefore thickening time is usually tested using the Bottomhole Circulating Temperature (BHCT), while the Compressive Strength development occurs as the slurry is heated up and stabilizes at the bottomhole Static Temperature (BHST). Accurate prediction and simulation of temperature and pressure is necessary for good and robust slurry design (Al-Yami and Nasr-El-Din, 2011).

Pore pressure can be normal, low (sub-normal) or high (abnormal). Normal pore pressure doesn't pose much of a problem and the drilling fluid or mud weight may be in the range of 8.5 – 9.5ppg lb/gal, but the requirement may be more stringent for deep wells in the range of 20,000ft. (Ravi et al,. 1991; Economides, 1998). Subnormal pressure wells usually require setting of additional casing strings to cover the low-pressure weak zones, while abnormal pressure well significantly affects casing / tubing design, mud type / mud weight, cement slurry weigh /design, and may cause stuck pipe, blow out, and hole instability, associated with high cost. Therefore, contingency plans must be in place for lost circulation, kicks / blowout and pipe sticking (Adams, 1985).

The geometry of the wellbore and casing sizes determine the annular volume to be filled with cement slurry, flow regime, and mud displacement efficiency. Irregular wellbores, washouts, or eccentric casing placement can result in non-uniform cement distribution and may result in channeling (Ahmed, 2019).

The annular velocity (V_a) during cement placement is given by:

$$V_a = \frac{Q}{A_a} \qquad (12)$$

Where:

Q= pump rate (m^3/s)

A_a= annular cross-sectional area (m^2)

Low annular velocities may result in laminar flow and poor mud removal, whereas excessively high velocities increase equivalent circulating density (ECD).

2.3 Fluids Compatibility

Incompatibility of the cement slurry with the drilling fluid can cause poor displacement efficiency, and poor zonal isolation. Poor displacement of the drilling fluid can result in contamination of the cement slurry. Spacer fluid is usually required to be compatible with both the cement slurry and drilling fluid, therefore often placed between the two fluids (Ravi, et al. 1992). Effective mud removal using flushes and spacers is vital to reducing mud contamination. Compatibility between the cement slurry and Spacer systems, drilling fluids and formation fluids, is critical and must be evaluated, to prevent contamination of the cement slurry, which can result to change of the cement slurry properties, gelation, sludge formation, poor fluid displacement, cement bonding issues, and entirely loss of performance (Anis and Smith, 1996; API, 2013).

Effective mud removal efficiency (η) is expressed as:

$$\eta = \frac{V_{mud\,removed}}{V_{mud\,initial}} \times 100 \qquad (13)$$

Centralization and spacer rheology play critical roles in achieving high displacement efficiency.

2.4 Operational and Fluid Placement

Cement placement techniques for primary and secondary (squeeze and plug) cementing jobs affect slurry design. Operational factors such as Hydraulics (pump rate, flow regime and displacement time) and annular clearance must be considered to ensure effective displacement (Annis and Smith, 1996; Joel, 2010). Centralization of the casing string also affects slurry behaviour during placement. Channeling risk and mud removal improve at high displacement rates with appropriate centralization. Other factors such as well-site condition, available technology, rig capabilities, and logistical constraints also influence slurry design decisions (Smith and Ravi, 1991).

Equivalent Circulating Density (ECD) is critical for wells with narrow pressure windows between the pore pressure and the fracture gradient. It accounts for the additional pressure created by frictional losses during slurry circulation in the well (Lake & Mitchell, 2006).

According to Bourgoyne et al. (1991), ECD can be expressed as follows:

$$ECD = \rho_c + \frac{\Delta P_f}{0.052 \times D} \qquad (14)$$

Where,

ECD= Equivalent circulating density (ppg)

ρ_s= Static cement slurry density (ppg)

ΔP_f= Total frictional pressure loss (psi)

D= True vertical depth (ft)

0.052 = Unit conversion constant (psi/ft per ppg)

2.5 HPHT, Gas, and Deepwater Wells

Cement slurry design for high-pressure high-temperature (HPHT), gas-bearing, and deepwater wells presents additional challenges as compared to conventional well cementing. Extreme temperatures and pressures require special material and methods, low temperature risk formation of hydrate, and drilling through gas laden zones risk gas migration through the slurry. All these factors require specialized slurry system and rigorous laboratory testing for quality assurance to ensure proper zonal isolation, lasting casing integrity and long-term well performance (Ravi, et al. 1991).

Deepwater and HPHT wells are usually associated with narrow margin between the fracture gradient and the pore pressure gradient (Smith, 1990). Therefore, the cement slurry density must be optimized to maintain well control while avoiding formation break down and loss circulation. In deepwater or over-pressured formations, low-density slurries are usually required to provide adequate hydrostatic pressure for well control and low enough to avoid formation fracturing (Azar and Samuel, 2007). More so, low fracture gradients near the seabed often require lightweight cement systems, formulated with extenders and/or hollow glass beads or foam cementing (Nelson & Guillot, 2006).

Cement slurry rheological properties influence Equivalent Circulation Density (ECD) and efficiency of fluid displacement. High ECD can cause formation fracture and loss circulation (Bourgoyne et al., 1991; Ravi, et al. 1991). Therefore, the cement slurry rheological properties must be optimized with dispersant, the plastic viscosity and yield point must be such that can ensure turbulent or pseudo-laminar flow without creating excessive pump pressure (Lake & Mitchell, 2006).

In HPHT wells and wells with permeable gas-bearing formations, high differential pressure increases rate of slurry dehydration, high fluid loss tendency, premature gelation, poor cement bonding and channeling (Nelson & Guillot, 2006). Effective fluid loss control is required. More so, Free fluid separation and particle settling are common, especially in deviated and horizontal wells, which can be checked using free fluid control and anti-settling or suspension aids (API, 2010).

Under HPHT conditions, cement hydration process increases, thickening time decreases, and strength retrogression tendency increases. At temperatures above approximately 110 °C, cement may experience strength retrogression due to the conversion of calcium silicate hydrate C–S–H phases (Nelson & Guillot, 2006). Therefore, 35 – 40% by weight of cement (BWOC) Silica flour is usually added to prevent strength retrogression, stabilizing the calcium silicate hydrate phases (Smith, 1990; API, 2013).

Cement strength development is commonly represented using a time-dependent logarithmic or power-law relationship.

Power-Law Strength model is as follows:

$$\sigma_c(t) = \sigma_{28}\left(\frac{t}{28}\right)^n \quad (15)$$

Where:

$\sigma_c(t)$= Compressive strength at time t(MPa)

σ_{28}= 28-day compressive strength (MPa)

t= Curing time (days)

n= Strength development exponent (0.3–0.7)

From the model, low temperatures, such as in deepwater wells. reduce the strength development exponential n, resulting in low strength development while Accelerators increase early-time strength development (Smith, 1990; Nelson & Guillot, 2006)

Strength retrogression may be represented with an exponential model as follows (Nelson & Guillot, 2006):

$$\sigma_r(t) = \sigma_0 \exp(-kt) \quad (16)$$

Where:

$\sigma_r(t)$= Residual compressive strength at time t(MPa)

σ_0= Initial peak compressive strength (MPa)

k= Retrogression rate constant (day^{-1})

t= Time at elevated temperature (days)

Cement sheath created in HPHT, multilateral and deep horizontal wells require to be more resilient than in conventional wells. Therefore, the Young's modulus, which is the ratio of stress to strain of a cement, needs to be determined for those conditions (Godwin and Crook, 1992). Additive selection and concentration, especially for retarders, needs to be optimized to produce high performance slurry with sufficient thickening time without creating excessive compressive strength delay (Nelson, 1990). In deepwater wells with low temperature, thickening time increases while compressive strength development decreases. This can be improved using accelerators and specially formulated low-temperature cement system (Smith, 1990).

Cement placement in deepwater and HPHT wells requires precise hydraulic modelling to control ECD and ensure effective mud displacement. Centralization, pump rate optimization, and spacer design are critical factors (Bourgoyne et al., 1991). ECD must be minimized to avoid fractioning the formation near the seabed. In deepwater wells, high viscosity and long annular lengths will increase the total pressure loss due to friction (Nelson, 1990; Lake & Mitchell, 2006).

III. Conclusion

Cement slurry design is an important part of oil and gas well cementing, aimed at achieving effective zonal isolation, casing support, and long-term well structural integrity. The design process must account for downhole conditions, the well geometry, job objective, cement slurry properties, additives, operational constraints, downhole fluids compatibility and slurry placement. Optimizing these variables enhances slurry performance tailored, to specific conditions for successful creation of competent hydraulic cement seal for the lifetime of the well.

Cement slurry designs for HPHT, gas, and deepwater water wells require a robust, detailed and integrated approach that considers the extreme temperature and pressure conditions, gas migration risk, narrow operational pressure margins, and harsh environmental constraints.

Cement placement in deepwater water wells requires precise downhole simulation and hydraulic modelling to monitor and control ECD and ensure effective drill fluid displacement. Casing strings centralization and optimization of pump rate, and spacer design are critical in achieving successful cementing.
Incorrect concentration and selection of additives can lead to job failure. All cement slurry systems and compatibility between the cement slurry and drilling fluids must be evaluated and validated with representative samples, under simulated downhole conditions, in the laboratory in accordance with recognized standards.

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