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Enhancing Well Integrity Self-Healing Cement as a Solution for Sustained Casing Pressure in Qatar

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Abstract

The North Field (Al Shaheen) in Qatar is one of the largest offshore projects in the region. The major operator managing the field has encountered Sustained Casing Pressure (SCP), a challenge that arises when fluid migrates through compromised well barriers, causing annular pressures at the wellhead that reaccumulate after being bled off. Despite enhanced placement techniques using conventional cement, SCP persists, highlighting the need for an alternative cement system capable of withstanding anticipated stresses and resolving this issue.

To address this challenge, a novel self-healing cement system was developed, which autonomously restores the integrity of the cement sheath when cracks or microannuli form and hydrocarbons come into contact with the cement. The cement is placed in the annulus using conventional methods, either across or above the hydrocarbon-bearing formation. Once in place, it acts as a dynamic pressure seal, expanding to accommodate downhole changes and healing upon exposure to hydrocarbons. This technology has been successfully tested in more than 17 wells within the field, delivering exceptional results.

The self-healing cement was used to effectively create an impermeable cap over the hydrocarbon-bearing zones. The cement formulation was specifically designed with a low Young's modulus, enhancing its mechanical flexibility and reducing susceptibility to fractures or the formation of microannuli. To mitigate the risks associated with cement integrity failure due to microannuli or microdebonding from chemical shrinkage post-setting, the formulation incorporated controlled linear expansion of up to 1.2%. This ensures a robust and resilient seal under varying downhole conditions.

Following placement, the wells underwent high-pressure testing while completing the well resulting in further inducing significant wellbore stresses on the cement placed in annulus. Despite these demanding conditions, the cement's self-healing properties enabled it to autonomously repair and restore wellbore isolation and structural integrity within 1 to 2 weeks, all without requiring external intervention. As a result, the self-healing cement system has been adopted as the standard for all future wells in the field, with plans to extend its use to other reservoirs facing similar well integrity challenges.

This paper provides a detailed demonstration of successful casing pressure remediation through the application of a flexible, engineered self-healing cement system. The design methodology, material selection, cement formulation, execution process, and performance evaluation are thoroughly analyzed, with particular emphasis on the engineering principles behind the cement's self-healing capabilities. These principles include the use of low Young's modulus for enhanced flexibility and the incorporation of linear expansion properties to counteract microannuli formation. The results offer valuable insights and establish a technical framework that will inform future well integrity management strategies, engineering practices, and operational procedures in similar subsurface environments across the global oil and gas industry.

Introduction

A leading operator in Qatar is executing drilling activities in one of the most geologically complex reservoirs within Block 5 of the Al Shaheen field (Figure 1). Located in Qatari territorial waters, approximately 80 km north of Ras Laffan, the field comprises 33 platforms and supports over 300 wells. As the largest offshore oil field in Qatar and among the largest globally, Al Shaheen primarily utilizes horizontal drilling techniques to develop four key formations: the Upper Mauddud limestone, Nahr Umr sandstone, Shuaiba limestone, and Kharaib limestone.

The new platform at Al Shaheen, initiated in 2025, commences with the installation of a 20-inch conductor pipe (CP) utilizing a hammer-driven method. This is followed by drilling a 16-inch hole section, which is stabilized with a 13-⅜-inch casing. Subsequently, a 12-¼-inch section is drilled, and a 9-⅝-inch production casing is set within the reservoir at measured depths (MD) between 4,500 ft and 8,500 ft. The wellbore is constructed to reach a 90° inclination, resulting in a true vertical depth (TVD) of approximately 3,400 ft. Within the 9-⅝-inch section, potential gas pockets have been identified in the Khatiya formation, presenting challenges for achieving effective zonal isolation. Khatiya Formation has equivalent mud weight of 16.5 ppg. In all the wells drilled on the platform, sustained casing pressure was observed following cementing of the 9-⅝-inch production casing in the 9-⅝-inch x 13-⅜-inch annulus. These issues were attributed to the cement sheath's inability to prevent gas migration through the cement matrix.

For example, the wells that drilled exhibited sustained casing pressure (SCP) of + 1000 psi [69 bar] after ~5 days completing the cementing job. The 9-5/8" section was cement with 14 ppg conventional Class G cement with gas control cement agents. The pressure was bled off and the sample was collected from annulus and was analyzed revealing a composition of above 95% methane and

To address this issue, a flexible and self-healing cement (FSHC) solution was introduced. Upon contact with hydrocarbons, the FSHC automatically activated its sealing mechanism without requiring surface intervention (Al-Yami et al., 2019). This self-healing capability is reactivated whenever annular integrity is compromised throughout the life of the well. FSHC is engineered to swell in the presence of methane and maintain a Young's modulus below 0.45 Mpsi, ensuring flexibility and durability under wellbore conditions (P. Cavanagh 2007).

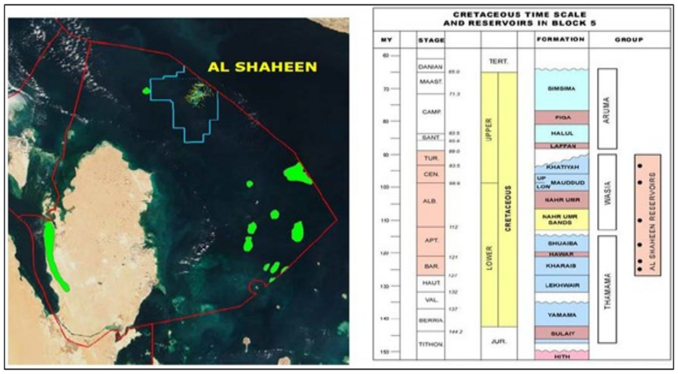


Figure. 1—Al Shaheen field offshore Qatar and right, stratigraphy of Al Shaheen field (Finlay et. al. 2014).

This advanced cement system has been deployed in ten wells to date. Eleven of these wells have already been successfully brought online with no signs of SCP. Pressure data from those wells clearly indicated the activation of the self-healing mechanism—first following the casing pressure test, and again the commencement of production.

At the time of writing, the remaining six wells are in the final stages of being brought into production. Given the proven effectiveness of this approach in mitigating SCP and enhancing long-term integrity, all the well in the current platform will be used with FSHC cement.

Problem Identification: SCP

Sustained casing pressure (SCP) is defined as any measurable casing pressure that consistently rebuilds after bleed-off. The most common causes of SCP are gas migration from high-pressure subsurface formations through the microannulus of a casing annulus, uneven cement placement, or cracks within the cement sheath.

Addressing SCP is most effective during the well design phase, where the cementing program can be optimized to deliver a solution tailored to the specific well conditions. This includes selecting cement systems with gas-blocking properties across gas-bearing zones and sufficient elasticity to endure downhole stresses over the well's life cycle. In the event of cement sheath failure due to elevated hydraulic stress, the cement should also possess self-healing capabilities to restore zonal isolation and maintain well integrity.

Extensive analysis has been done to understand the root causes of the SCP problem on particular platforms, and it has been found that the complex gas migration below 13-3/8" formation is the main reason of sustained casing pressure in the 9-5/8-in x 13-3/8-in annulus. Gas fingerprinting and analysis revealed that the annulus bleed-off gas contains over 95% methane.

Design Methodology

The well section of interest pass through multiple high-permeability intervals and gas-bearing reservoir specifically formations (Nahr Umr & Khatiya formation) that pose a significant risk to the long-term integrity of the 9 5/8-in. casing cement sheath. These formations, if inadequately isolated, present a viable conduit for gas migration, especially in cases where zonal isolation is compromised due to suboptimal cement placement, inadequate mud displacement, or the use of cement systems lacking requisite gas-blocking and mechanical resilience characteristics (Yeager, M., et al. 2019).

Although the Al Shaheen fields exhibit some distinct characteristics, the primary formation parameters—as well as the key cementing objectives and challenges for the production casing—are largely comparable. The most notable variation between certain wells lies in their configurations, specifically the requirement for dual-string completions. The equivalent circulating density (ECD) window is tight due to increased frictional pressure losses across the 9⅝-in. × 13⅜-in. annular space (Al-Khudair, A. 2019). The design methodology outlined below is applicable to both fields. Broadly, the approach can be structured into the key components below:

1. Cement Slurry Design
    - i. Self-Healing Properties of Cement
    - ii. Control of Gas Migration
    - iii. Mechanical Properties of the cement
2. Placement of FSHC Cement Slurry

Cement Slurry Design

A conventional Class G cement system with expanding agents was historically used to cement the 9 5/8 in. casing sections. Although the slurry design was engineered to withstand long-term mechanical loading, sustained casing pressure (SCP) was observed as early as two days after cement placement. Several optimization attempts were conducted, including modifications to cement slurry components, with particular focus on gas control additives; however, these changes did not result in measurable improvement in SCP performance. The early onset of SCP suggests degradation of zonal isolation, likely due to the development of cracks and/or micro-annuli within the cement sheath caused by pressure cycling and wellbore-induced stresses. These defects provided a flow path for gas containing more than 95% methane to migrate between zones and reach surface. As a result, a fundamentally different cementing approach was adopted. The cement system was redesigned to incorporate a flexible, self-healing cement slurry, specifically tailored to the wellbore conditions through optimization of gas control performance and enhancement of mechanical properties to mitigate SCP.

Flexible Self-Healing Cement Slurry (FSHC)

The Flexible Self-Healing Cement system is engineered to respond to contact with hydrocarbons by activating an autonomous sealing mechanism. The system is intended to enhance long-term well integrity by maintaining annular pressure isolation throughout the well lifecycle, from drilling through abandonment, and by mitigating hydrocarbon leakage and sustained casing pressure at the wellhead. The cement system exhibits elastic mechanical behavior, enabling it to accommodate wellbore stresses while maintaining zonal isolation.

The FSHC system functions as a secondary barrier in scenarios where the primary gas-tight cement sheath fails due to cracking and/or debonding. Its elastic properties improve resistance to stress-induced damage; however, in the event that isolation is compromised, the cement undergoes a self-healing process upon exposure to hydrocarbons. This process is independent of methane concentration and effectively seals leakage pathways, preventing upward migration of fluids to surface. Design and implementation of the FSHC system require an understanding of the hydrocarbon composition produced by the formation to ensure effective activation of the self-healing mechanism. Upon contact with oil, gas, or condensate, the cement undergoes controlled swelling, thereby sealing defects and restoring annular isolation.

Validating Flexible Self-Healing Cement Slurry for Oil rich environment

The self-healing behavior of the cement system was evaluated using a modified expansion test based on the ASTM C490 procedure. Fresh cement slurry was placed into a calibrated ASTM C490 expansion mold to enable measurement of linear dimensional changes during setting and post-set exposure. The specimen was initially cured under controlled laboratory conditions to allow cement hydration and strength development. Following the initial curing period, the cement sample, while remaining constrained within the expansion mold, was fully immersed in diesel to simulate hydrocarbon exposure representative of downhole conditions. After initial curing, the cement specimen was submerged in diesel to simulate hydrocarbon exposure. Dimensional changes of the cement were monitored as a function of time to quantify expansion behavior upon contact with hydrocarbons. The measured expansion as shown in Figure 2 was used as an indicator of the cement's capacity to activate a self-healing response, with swelling suggesting potential for closure of micro-annuli or defects within the cement matrix.

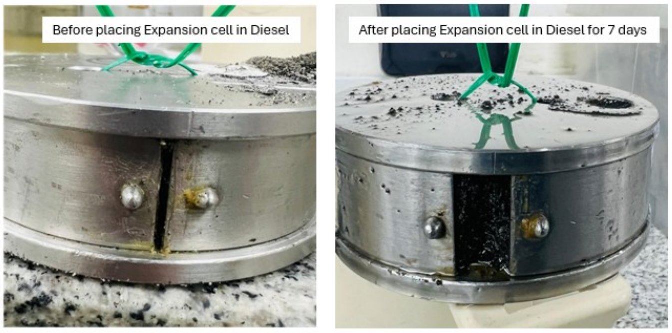


Figure 2—SFHC cement expansion in Diesel

Validating Flexible Self-Healing Cement Slurry for Gas rich environment

Laboratory experiments of a self-healing cement stone system under dynamic methane flow, with the objective of quantifying its ability to reduce permeability across induced microfractures through reactions between FSHC cement cores and methane. The test program used cured FSHC cement cores as shown in Figure 3 and high-purity methane (99.9%). Core preparation followed established core-analysis practices (GB/T 29172-2012), including coring, end-face polishing, and vacuum drying at 80°C.

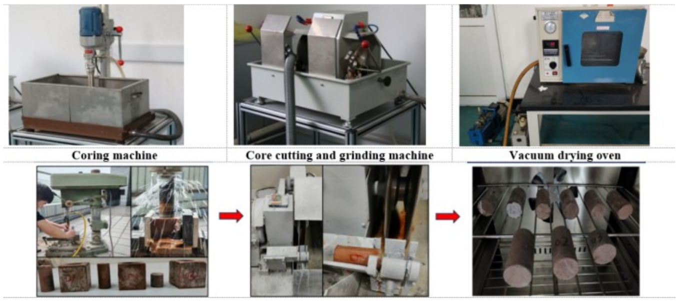


Figure 3 - Core processing flow chart and physical images

Fractures were generated using a Brazilian splitting method to create reproducible, centerline cracks. For dynamic testing, split cores were reassembled and treated to ensure stable handling and repeatable initial flow conditions: 0.2-mm copper foil shims were applied to control fracture closure during confining pressure loading, fracture faces were bonded to prevent edge channeling, and the cores were wrapped using heat-shrink tubing to maintain integrity in the core holder. The dynamic self-healing evaluation was conducted at 70°C with 7 MPa back pressure under constant-pressure flow. Confining pressure was adjusted to ensure comparable initial fracture permeability within a target range of ~10–50 mD, then the injected gas was switched from nitrogen to methane while permeability was continuously calculated from measured inlet/outlet pressures and flow rate.

Across two fractured FSHC cement cores the initial gas permeability of FSHC core sample 1 was 21.99 mD. After approximately 129 hours of methane gas exposure under high-pressure conditions, permeability decreased to 3.68 mD, representing an 83.04% reduction. The initial gas permeability of cemented rock core sample 2 was 22.65mD. After high-pressure methane gas displacement for about 129 hours, the gas permeability decreased to3.12mD, with a reduction of 85.98%. The permeability evolution of both cores are shown in Figure 4. These results indicate that, under the tested conditions, the self-healing cement stone exhibited a time-dependent reduction in fracture conductivity during methane flow, consistent with progressive sealing of the induced fracture pathways.

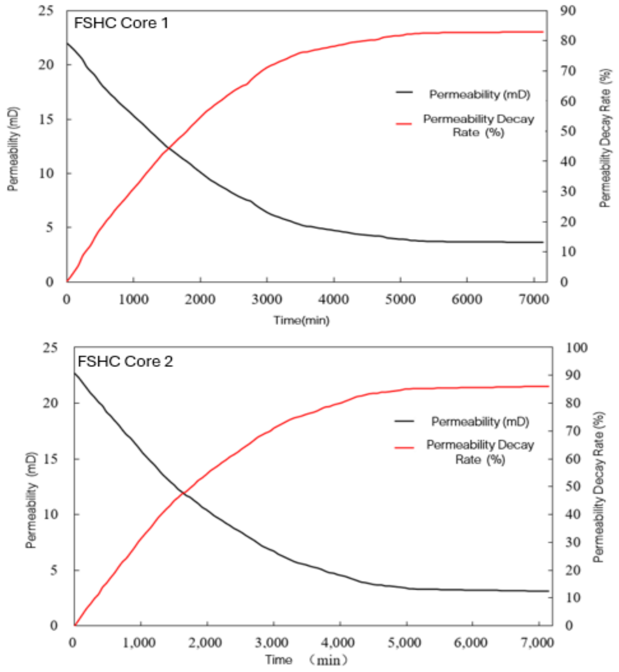


Figure 4 Methane Permeability Reduction Measured Across FSHC Cement Cores

Control of Gas Migration

Gas migration remains a critical challenge during well cementing operations and influenced by several important factors such as fluid density management, effective mud displacement, properties of the cement slurry, how the cement sets (hydrates), and the quality of the bond between the cement, casing, and surrounding rock. According to (Nelson, 2006), three primary conditions must be present for gas to migrate through the annulus:

1. The pressure from the fluid column in the annulus becomes equal to or less than the pressure in a gas-bearing formation.
2. There is enough open space in the annulus to allow gas to enter.
3. There is a continuous pathway that allows gas to move upward.

The first condition—annular pressure decay—is addressed during slurry placement through the application of backpressure and the use of a lead cement slurry with extended thickening time, as discussed in subsequent sections. The remaining conditions, namely the presence of open space and a continuous migration pathway, are mitigated through optimized cement slurry design and placement practices. These include the use of gas migration control additives, elimination of free fluid, low fluid loss characteristics, increased solid volume fraction, and improved mud removal achieved through optimized centralization and spacer design. The FSHC systems are formulated using:

- Incorporate latex additives in the cement formulation
- Zero free fluid
- Maintain low fluid loss (less than 20 mL according to API standards)
- Static Gel Strength from 100 lbf/100 ft^2 to 500 lbf/100 ft^2 should be less than 20 mins
- Cement slurry should pass the Cement Hydration Analyzer (CHA) test

The FSHC cement system is formulated with a higher solid volume fraction (~43%) compared with conventional cement systems (~31%), thereby reducing pore volume and limiting the available open space for gas migration within the cement sheath. In addition, the incorporation of latex additives into the slurry provides an additional impermeable barrier to gas flow. Latex additives used in FSHC systems for gas migration control consist of aqueous dispersions of solid polymer particles stabilized by surfactants and protective colloids. These components ensure dispersion stability within the cement slurry and prevent premature particle agglomeration. During slurry preparation and placement, latex particles are uniformly dispersed and remain as discrete particles throughout early cement hydration. Upon the onset of gas migration, gas invades the cemented annulus across the gas-bearing interval, causing localized dehydration within the cement pore structure. This dehydration triggers coalescence of the latex particles within the pore spaces, forming a continuous polymer film that is impermeable to gas. The resulting film is uniformly distributed throughout the cement matrix, effectively blocking gas flow and preventing further migration. In the absence of gas, latex particle coalescence occurs more gradually and is governed by the rate of water consumption during cement hydration. Under these conditions, polymer film formation is delayed, typically occurring over several weeks at ambient temperature and several days at elevated temperatures. This mechanism has been proved by a Scanning -Electron Microscope investigation of cement samples at different curing times with or without gas injection, as below.

i. Class G Cement without Latex
ii. Class G Cement with Latex
iii. Class G Cement exposed to gas
iv.

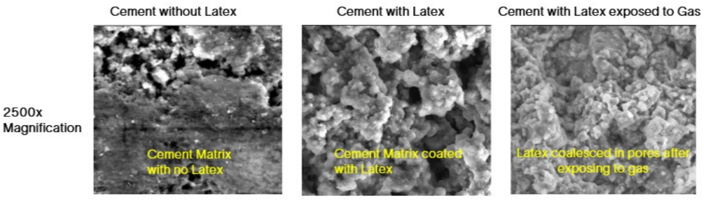
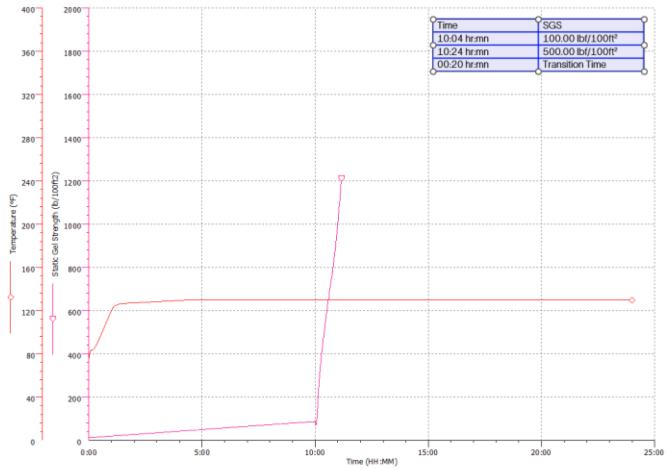


Figure 5: Scanning Electron Microscope (SEM) tests on Set Cement

The SEM analysis (Figure 5) shows well-defined pore structures in unmodified Class G cement samples. In contrast, latex-modified samples exhibit pore surfaces coated with polymer films at 2500× magnification. In samples subjected to gas exposure, pore spaces appear effectively sealed. These observations confirm the proposed mechanism whereby latex particles coalesce within cement pore spaces upon gas exposure, resulting in pore closure and enhanced resistance to gas migration.

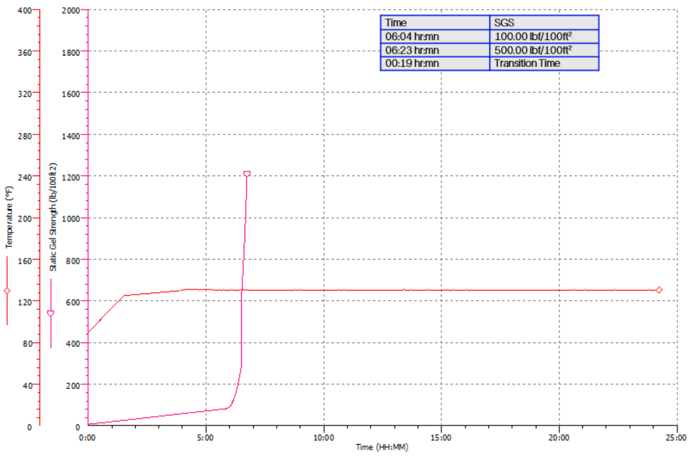
An essential factor in evaluating the risk of gas migration during primary cementing operations is the point at which the cement slurry reaches its Critical Static Gel Strength (CSGS). CSGS represents the threshold gel strength at which the hydrostatic pressure exerted by the cement column is no longer sufficient to counteract formation pore pressure, thereby allowing gas to enter the cement matrix. According to industry standards, a gel strength of 500 lbf/100 ft^2 is typically considered the minimum required to arrest gas movement through the cement column (API RP 10B-2, 2013; Nelson & Guillot, 2006). Equally important is the time required for the slurry to transition from the 100 lbf/100 ft^2 to this 500 lbf/100 ft^2 benchmark. Best practices recommend that this transition should occur within 45 minutes to minimize the risk window for gas intrusion. However, for the current study the transition time of the cement is designed to be lower than 20 minutes to ensure a rapid development of structure within the cement, improving its capacity to resist gas flow. In the current study, the gel strength hierarchy between the lead and tail slurry was properly maintained. The tail slurry achieved a gel strength of 500 lbf/100 ft^2 before the lead slurry reached 100 lbf/100 ft^2 as shown in Figure 6. This controlled gel strength progression is critical in ensuring zonal isolation, particularly in multi-stage cementing operations, as it prevents premature pressure build-up and enhances sealing efficiency.

SGSA Lead Slurry



Time	SGS
10:04 hr:mn	100.00 lbf/100ft²
10:24 hr:mn	500.00 lbf/100ft²
00:20 hr:mn	Transition Time

SGAA Tail Slurry



Time	SGS
06:04 hr:mn	100.00 lbf/100ft²
06:23 hr:mn	500.00 lbf/100ft²
00:19 hr:mn	Transition Time

Figure 6: SGSA Test Result

The FSHC cement slurry design was also evaluated using a Cement Hydration Analyzer (CHA) to monitor the hydration kinetics under simulated downhole conditions. By measuring the heat evolution rate during cement hydration, the CHA provided critical insights into the onset and progression of the hydration reaction. This allowed for assessment of the effects of various additives on the slurry's setting behavior and early strength development. The data obtained enabled optimization of the formulation to ensure timely gel strength development and minimize the risk of gas migration. Overall, the CHA proved instrumental in tailoring the cement slurry's chemical reactivity to achieve reliable performance in wellbore conditions.

The slurry is subjected to a confining pressure and due to the liquid nature of the slurry; cement pore pressure would be the same. Initially the formation gas pressure is the same as the gas injection pressure. This pressure is lower than the cement pore pressure; therefore, the gas would not migrate through the cement slurry column. During the hydration, the cement undergoes phase changes from liquid to gel before it becomes self- supporting. As a result of these changes the cement pore pressure will drop to a point where it is lower that the injection pressure; this causes the gas injection to be activated thus simulating gas migration through the cement column. If the pore pressure increases and becomes equal to the gas injection pressure, the slurry is not gas tight. In case the pressure stays below the gas injection pressure it shows a gas tight system. Figure 7 showed the designed FSHC system is gas tight based on the test result.

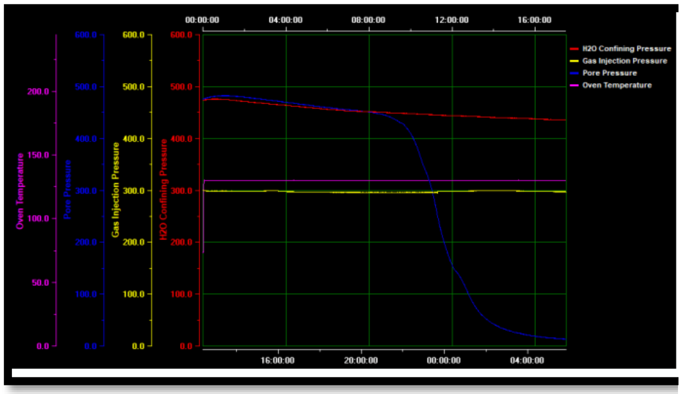


Figure 7: CHA Test Result

Mechanical Properties of Cement Slurry

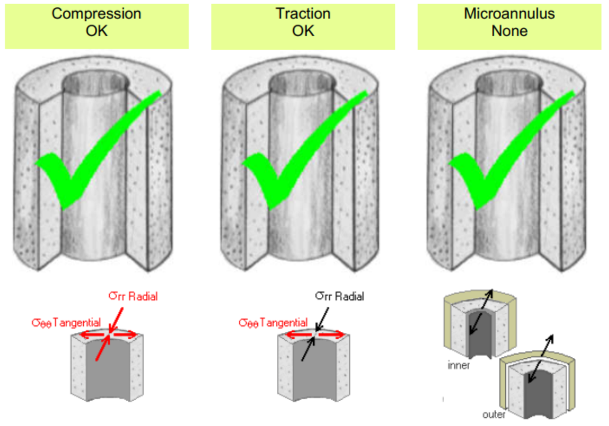
In the weeks and months following a cementing operation, mechanical stresses such as those introduced during casing pressure tests or perforation activities can compromise the cement sheath. These forces may lead to structural issues, including failure under compression or tension, or the formation of microannuli—narrow gaps between the cement and casing or formation. These openings can eventually serve as pathways for hydrocarbon migration. Sustained Casing Pressure (SCP) evaluations on previously cemented wells revealed that integrity issues commonly arise during the following operational phases:

- **Post casing pressure testing**, particularly when the test is performed after the cement has hardened but before it has fully bonded to the casing or formation, making it susceptible to mechanical stress.
- **While drilling the subsequent hole section**, where increased downhole temperatures and intensified vibration loads may induce stress on the cement structure.
- **Immediately after well startup**, when abrupt pressure changes and fluid movement can compromise the cement sheath.

FSHC cement sheath as a primary barrier was designed to withstand the stresses by enhanced elasticity and a reduced Young's modulus, demonstrating improved ability to maintain integrity under mechanical stresses encountered during well operations. In addition to improving the elasticity, self-expansion additives were added to the FSHC cement design to substantially improves hydraulic sealing performance (Laidler, A.,2007). The elastic characteristics of the cement matrix are typically influenced by the choice of cement components and the specific slurry additives incorporated. To evaluate these properties, Young's modulus and Poisson's ratio were determined through cyclic loading tests. Tensile strength was assessed using the Brazilian test method, which measures the maximum tensile load the sample can endure before failure. Mechanical testing was performed using an MTS Insight 200 load frame, equipped with a load cell and axial and radial displacement transducers. The strain rate was maintained at a constant one millistrain per minute during deformation measurements. Below (table 1 and figure 8) is the test measured in actual cement sample:

Unconfirmed Compressive Strength (UCS)	Young's Modulus	Tensile Strength (Brazilian Test)
1766 psi	0.45 M	254

Table 1: Mechanical Properties Test result



Shear (also known as Compressive):
Cement will not fail in shear. Maximum Mohr-Coulomb shear stress encountered after 354240 min at inner casing-cement boundary in inner cement (4.81 in from well axis).

Maximum Mohr-Coulomb Stress: 1547 psi.
Compressive strength: 1766 psi.

Traction (also known as Tensile):
Cement will not fail in traction. Maximum tensile stress encountered at the beginning of simulation inside the well.

Maximum tensile stress: 0 psi.
Tensile strength of cement: 254 psi.

Microannulus:
No Microannulus detected

Figure 8: Stress Analysis Results for the FSHC Cement Sheath

After conducting thorough analysis and gathering information on the hydrocarbon formulations, a flexible, expanding, self-healing cement (FSHC) system was selected for placement above the reservoir formation, across the existing casing. This system is intended to activate in the event of mechanical failure within the cement matrix structure of the primary gas-tight barrier. The self-healing slurry was specifically formulated to meet the unique conditions of this field, where the gas composition is 95% methane

The FSHC slurry was prepared and tested following the procedures outlined in API RP 10B-2, including measurements of thickening time, fluid loss, free water, and rheology. Before each test, the slurry was conditioned in a high-pressure, high temperature (HPHT) consistometer according to the test schedule defined by the hydraulic placement simulator for the actual job. Additionally, an expansion test was conducted to verify minimal shrinkage, and an API sedimentation test was performed to ensure slurry stability.

The slurry's compressive strength and static gel strength development under downhole conditions were quantified using an ultrasonic static gel strength measurement device. It was confirmed that the slurry would develop 100 lbf/100 ft² later than the tail slurry reaches 500 lbf/100 ft², ensuring full hydrostatic pressure transmission during the critical static gel strength period of the tail gas-tight slurry.

The FSHC cement formulation and its key properties are summarized in **Table 2.**

Comparison	Conventional Class G with expandable material		Flexible Self-Healing Cementing	
Density, lbm/gal	14		14.3	
Rheology	PV	115 cP	PV	124 cP
	Ty	13 lbf/100ft²	Ty	13.72 lbf/100ft²
Free Fluid, ml in 2hrs	0		0	
Fluid Loss, ml in 30 mins	20 ml		20 ml	
Thickening time, hr:mn	06:56 hr:mn		07:11 hr:mn	
Time to reach 500 psi Compressive Strength, hr:mn	11:05 hr:mn		09:0 hr:mn	
Compressive Strength in 24 hrs, psi	1325 psi		1535 psi	
Static Gel Strength Test in 24 hrs, min	19 min		19 mins	

Table 2: FSCH slurry comparison with Conventional Cement

Placement of FSHC Cement Slurry

The initial stage in the cementing design process focuses on ensuring that cement slurries can be placed safely and effectively. This involves displacing the drilling mud efficiently and achieving uniform 360° annular coverage, particularly above zones requiring hydraulic isolation.

To support this, an advanced zonal isolation software tool (Isgenderov et al., 2014) was utilized to simulate the cementing operation and optimize key parameters—including fluid volumes, densities, rheological properties, centralizer placement, and pumping schedules. The objective was to maintain the equivalent circulating density (ECD) within an acceptable range while maximizing mud displacement efficiency (Therond et al. 2018).

Beyond primary cementing simulations, the software incorporates a sophisticated centralization model that considers casing orientation within the wellbore and simulates mud displacement by coupling in-pipe mixing dynamics with annular flow behavior. It also accounts for casing rotation, reciprocation, and azimuthal flow variations. Figure 3 illustrates typical outputs related to mud displacement and fluid placement. To ensure a gas-tight seal across all zones and provide sufficient length for a secondary barrier, below modifications were done to the cementing primary cement placement

- **Three plug systems** have been planned to reduce the contamination inside the casing
  - One bottom plug between spacer and lead slurry
  - One bottom plug between lead and tail slurry
  - Top Plug
- **Tail slurry**: Designed at 14.3 ppg density, it acts as the primary barrier to prevent gas migration. Tail slurry will cover from 9⅝-in shoe to 500-ft inside previous casing shoe
- **Lead slurry**: Pumped ahead of the tail slurry at 14.3 ppg density (see Table 1). The lead slurry have longer Thickening time and it will stay in liquid phase while the tail slurry starts to transition from liquid to solid. This enables lead slurry to act as a liquid hydrostatic column above tail slurry and serve as a secondary barrier in the event of tail slurry failure.
- **Back-Pressure:** 300-psi back-pressure was designed to put in 13-3/8" x 9-5/8" annulus after cement is in place. It is to overcome Khatiya Formation has equivalent mud weight of 16.5 ppg during cement setting period

To address uncertainties in open hole (OH) capacity beyond the sonic caliper data acquired during drilling—35% over open hole (12.25-in) was employed. This will ensure cement return to surface and more effective in containing gas migration for the rest of the well life. Following rigorous laboratory evaluation and qualification, the optimal formulation for each cement system and spacer was established, based on solid volume fraction (SVF) parameters.

The placement rate was optimized to have good mud removal. Higher pumping rate was adopted to have proper displacement to mitigate channeling in highly deviated well. Mud displacement simulation was performed to observe proper displacement achieved during cementing operation (Figure 9).

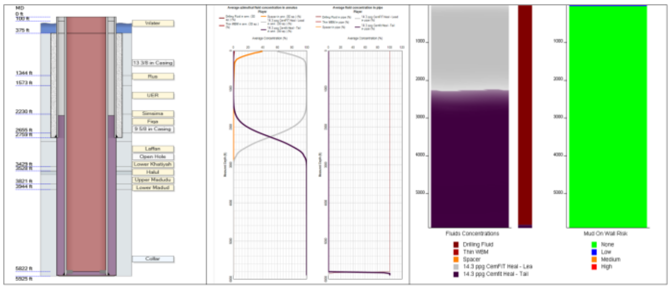


Figure 9: Typical Mud Displacement Simulation

Case Studies

A 12 ¼-in. OH section of well A was drilled with 14.0 ppg water-based mud (WBM) to a depth of 5000 ft MD [3419 ft true vertical depth (TVD)]. Suspected gas bearing formation were penetrated below the previous casing shoe (Nelson, E. B, 2010)

All the primary cementing best practices were implemented on the 9 5/8-in. production casing, including effective mud removal. Gas migration severity analysis was performed to define the SGS development requirements.

A 14.3-ppg gas-tight tail cement slurry with optimum thickening time was placed across all the hydrocarbon-bearing formations with the top placed ~ 500 ft inside previous casing shoe, taking into consideration the worst-case scenario where OH size is equivalent to 35% of annular excess applied over the sonic caliper data obtained during drilling the section. From Top of Tail to surface, 14.3 ppg FSHC cement slurry were placed above as a sealing cap. The length of both slurries was defined based on the advanced simulation zonal isolation software so that sufficient length of the minimal contaminated slurry could be obtained and ECD was within acceptable margin.

The job was successfully executed, with no losses during cementing. 300 psi back pressure was applied between 13-3/8-in and 9-5/8-in Annulus till pressure drop.

Post Job Analysis

The 9 5/8-in, casing cementing job was completed successfully with no losses during pumping cement slurry and displacement. The top plug was bumped in the end of displacement. Floats were confirmed holding after bleeding off on cement unit. During the job, 74 bbl of pure 14.3 ppg lead slurry were received at the surface.

Playback shows acquired pressure as a blue line and simulated pressure as a green line in **Figure 10.** Playback showed the tendency of pressure during the job matched the pre-job modeling and final displacement pressure matches the simulation.

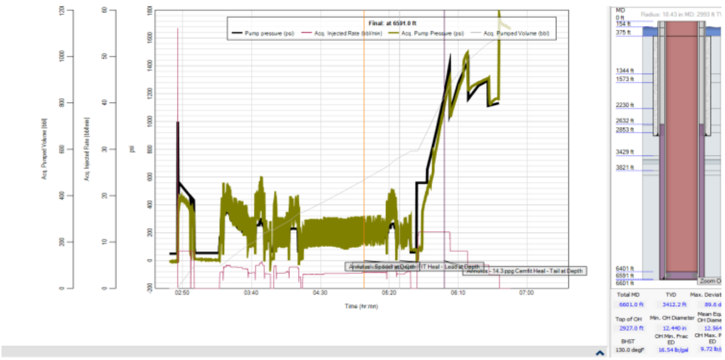


Figure 10—Cement treatment plot (pressure, rate, and density).

The pressure gauge was installed to monitor the pressure in annulus. No sustained casing pressure was observed in below 11 wells till date (table 3) but with minimum amount of pressure trapped in the annulus

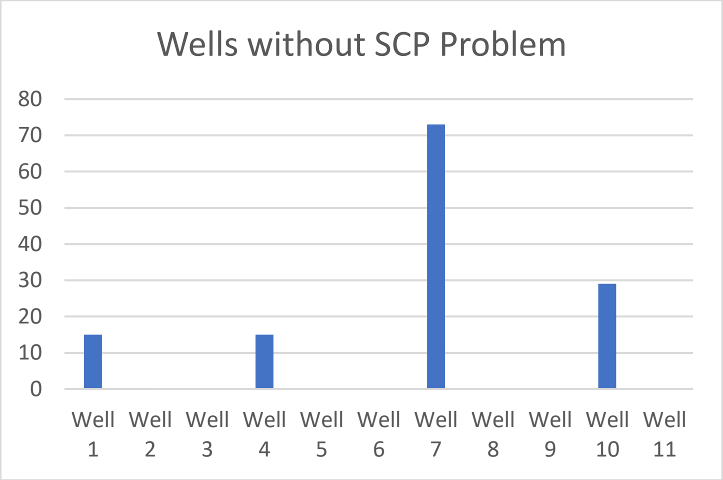


Table 3: Total wells without sustained casing pressure

Conclusion

This study addressed sustained casing pressure (SCP) challenges observed in the 9⅝-in. production casing in the Al Shaheen field, Qatar, where methane migration through the cement sheath was identified as the primary cause of annular pressure buildup. Conventional gas-control cement systems were unable to maintain long-term zonal isolation under these conditions, necessitating an alternative cementing approach.

A flexible self-healing cement (FSHC) system was designed, qualified, and implemented to mitigate gas migration and enhance cement sheath integrity. Laboratory testing demonstrated gas-tight behavior through rapid static gel strength development, zero free fluid, low fluid loss, and a high solid volume fraction. SEM analysis and Cement Hydration Analyzer testing confirmed effective pore sealing upon gas exposure. Mechanical testing showed elastic behavior with a low Young's modulus, adequate compressive and tensile strength, and controlled post-set expansion, supporting resistance to stress-induced damage. Dynamic core-flood testing demonstrated significant permeability reduction following methane exposure, indicating autonomous fracture sealing. Cement sheath stress modeling predicted that the FSHC system can withstand anticipated pressure and temperature cycling with reduced risk of compressive, tensile, or microannular failure. Optimized placement design and displacement simulations ensured effective mud removal and controlled ECD during field execution. Field application was completed without operational issues, and no sustained casing pressure has been observed in wells cemented with the FSHC system to date. These results indicate that the integrated application of a flexible self-healing cement system and optimized placement practices can provide an effective approach for SCP mitigation in gas-prone reservoir environments.

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Nomenclature

m^3/h = *Metric cube per hour*
kg/m^3 = *Kilogram per metric cube*
in^2 = *Inch Square*
MD = *Measure Depth*
TVD = *Total Vertical Depth*
bbl/hr = *barrel per hour (bph)*
ft = *feet*
in = *inch ('')*
µm = *micron*
gpm = *gallons per minute*
ppg = *pound per gallon*
°C = *Degree Celsius*
°F = *Degree Fahrenheit*
BHST = *Bottom Hole Static Temperature*
bbl = *barrel*
psi = *pound per square inch*
rpm = *Rotations per minute*
MASP = *Maximum Allowable Surface Pressure*
LCM = *Lost Circulation Material*

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