



Society of Petroleum Engineers

SPE-227891-MS

Long-Term Study of CCUS Cement Designs Under Static and Cyclic CO₂-Conditions

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Copyright 2025, Society of Petroleum Engineers DOI [10.2118/227891-MS](https://doi.org/10.2118/227891-MS)

This paper was prepared for presentation at the SPE Annual Technical Conference and Exhibition held in Houston, Texas, USA, 20 - 22 October 2025.

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Abstract

With the emerging focus of zonal isolation for underground storage projects, and the potential uncertainty of applicability of current barrier materials when exposed to a corrosive environment alongside added mechanical stressors a long-term exposure study was conducted.

A base design known as a fit-for-purpose design for corrosive exposure was selected, with two additional permutations that would enhance the resistance towards the wellbore environmental risks. The study entailed a six-month long test schedule with intermittent sampling at one-three- and six-month intervals of the exposed plugs. Mechanical properties testing and complementary micro-CT scans were completed on the plugs in two separate laboratories and are detailed in this paper. Furthermore, the impact of constant pressure and temperature conditions in comparison to cyclic conditions was investigated. Aided by software simulations, a comparative discussion of the three designs was done to select the optimum design for a specific well scenario in the North Sea.

Even though all considered cement systems showed an outstanding resistance towards CO₂-saturated brines, minor differences based on the selection of additives could be observed. In addition, the choice of either static or cyclic test conditions also contributed to the degree of reaction during exposure. The realistic rather slow changes of the conditions given by the operational sequence for the well do not impose any impactful stress on the samples. Whereas the dominant factor appears to be the average partial pressure of CO₂.

Introduction

Oil and gas, a cornerstone of global energy supply, faces mounting pressure to transition towards more sustainable and environmentally responsible practices. Among the significant challenges is the mitigation of CO₂ emissions, a primary driver of climate change. In response to the urgent need to reduce greenhouse gas emissions, many operators and stakeholders are increasingly adopting Carbon Capture and Storage (CCS) and Carbon Capture, Utilization, and Storage (CCUS) technologies. These initiatives are crucial for the industry's commitment to achieving net-zero carbon emissions and ensuring a sustainable energy transition.

They play a key role in significantly reducing the overall carbon footprint of fossil fuel extraction and consumption.

In this context, the integrity of wellbore cement systems becomes critically important. These systems are essential for isolating geological formations and preventing the escape of CO₂ and other fluids to the surface. Traditional oil well cement systems, while effective in many applications, demonstrate significant drawbacks when exposed to CO₂-rich environments [1-3]. Such conditions can lead to the degradation of cement integrity through processes such as carbonation, ultimately compromising the wellbore's long-term sealing and containment capabilities. Lack or loss of sealing is often referred to as lack of zonal isolation (ZI). Loss of zonal isolation can have severe consequences such as sustained casing pressure (SCP) or in worst case leaks of injected or reservoir fluids to the external environment. Poor inter-zonal isolation can also lead to cross flow and/or injection of CO₂ in the incorrect zone. Lack or loss of ZI often leads to expensive and sometimes difficult repair programs to remediate. Finally, there is an obvious increase in CO₂ emissions that can arise from the combination of SCP and leaks and/or loss of ZI integrity.

This study was initiated as part of the planning of CO₂ injector development wells on a CCS license on the Norwegian Continental Shelf (NCS). The license is located in the North Sea with an estimated CO₂ injection capacity of > 5 Mt CO₂/year. The target reservoir for injection is the saline aquifer in the Statfjord formation with top at ~3000 m TVD, and water depth on the location is ~200 m. The reservoir pressure and temperature are estimated to ~312 bar and ~115 °C. Initial well design plans include a 7" cemented liner across the Statfjord reservoir, and with a 9 5/8" cemented production casing/liner set just above the reservoir. The interval with the most critical cementation will be the 9 5/8" casing/liner with the following conditions and preliminary design parameters (see Table 1).

Table 1—Preliminary conditions for the 9 5/8" Production Liner Casing.

Parameter	Value
Slurry density	1.90 - 1.95 SG
Bottomhole Static Temperature (BHST)	112 °C
Bottomhole Circulating Temperature (BHCT)	70 °C

Simulation

The mechanical property requirements of the cement were simulated using the expected parameters of the well. Simulation was done pre-study to evaluate the property targets that would pass the expected stresses, post-study simulation was also done as shown in the Discussion chapter. A numerical wellbore stress software was used to verify that the mechanical and elastic characteristics of the cement system would ensure the cement sheaths integrity throughout the lifetime of the well. This software, based on a series of empirical equations, can be used for preliminary design purposes to assess the durability of specific cement slurry properties to accommodate the stresses imposed on it during well completion and production operations.

Experimental

Objectives, Conditions and Criteria

The objective of the study is to determine the potential negative/beneficial properties of all three CCUS cement designs under a 2-week brine cure followed by 6-months of CO₂ exposure. To determine the integrity of each cement design, under CO₂ exposure, a series of testing was incorporated. The following performance criteria are set as shown in Table 2 and all cement slurries are also designed to be gas tight, as per API criteria below (Table 3).

Table 2—Performance CO₂ exposure Criteria.

Parameter	Criteria	Comments
Visual appearance	No flaking, cracks, and micro cracks	Incl. micro-CT
Volume	No shrinkage	
Permeability	Low (< 0.1 mD)	Towards gas
Compressive Strength	> 500 psi	Uniaxial Compressive Strength (UCS)

Table 3—API RP 65-2 criteria for gas tight cement designs.

Parameter	Criteria
Thickening Time	5-6 hours until reaching 30 Bc
Fluid Loss	< 50 mL/30min
Free Fluid	Zero to trace with cylinder inclined 45° angle
Compressive Strength	> 3000 psi
Critical Static Gel Strength	500 lb/100 ft ² in less than 45 minutes

For the CO₂ injector wells, the service company's and the operator's laboratory (Technology & Service Center, TSC) were both tasked to determine the optimum design to withstand the conditions the cement would be subjected to.

Based on the requirements of the CO₂ injector development three designs were formulated as stated in Table 4. A reduced Portland based system was selected as a base due to the presence of Portlandite generated during the generation of API well cements (A-H) when manufactured according to API specification. Portlandite does not provide strength to the system and can be considered a weak point in a corrosive well environment, as the Portlandite is susceptible to leaching. API well cements are porous, and with the presence of water in the pores allow for a pathway of strength deterioration of the overall system. [4]

Table 4—Systems evaluated for study

System	Description
System A	Reduced Portland based system with increased resistance towards corrosive well environments
System B	System A with addition of flexible additives to increase resistance towards mechanical stressors
System C	System B with addition of latex additive to reduce permeability matrix to increase corrosion resistance

The formation brine composition is given in Table 5 - Brine composition.

Table 5—Brine composition.

Ion	Ba ²⁺	Sr ²⁺	Mg ²⁺	K ⁺	Ca ²⁺	Na ⁺	Fe ²⁺	Cl ⁻	SO ₄ ²⁻	HCO ₃ ⁻
mg/L	250	390	340	550	4090	16210	11	34000	0	320

Methods

Cement Plug Preparation. All three cement slurry designs were tested, optimized and qualified for their purpose using standard API well cement testing in accordance with API RP 10B-2 Recommended Practice for Testing Well Cements (see results in Table 6). The slurries were mixed at a density of 1.9 SG using fresh water. The molds used to fabricate the cement plugs were cured for 96 hours at BHST of 110 °C at 3000 psi in fresh water.

Table 6—API well cement testing results (15.8 ppg, BHST = 112 °C, BHCT = 70 °C).

Parameter	System A	System B	System C
Free Fluid at BHCT (45°)	0	0	0
API Fluid Loss at BHCT	32 mL/30 min	38 mL/30 min	38 mL/30 min
PV at room temperature/at BHCT	254/201	320/200	243/206
YP at room temperature/at BHCT	35/44	41/38	43/40
Thickening Time (until 70 Bc)	5 h 52 min	6 h 27 min	6 h 53 min
Compressive strength (500 psi/24 h)	8 h 40 min/4486 psi	11 h 02 min/3907 psi	11 h 48 min/3983 psi

After curing, all set cement molds were removed from the curing chamber, the cement plugs removed from the molds and the samples separated for each system. From each design, three 1" by 2" plugs and two 2" by 1" pucks were captured for baseline mechanical properties measurement. The remaining samples were returned to a curing chamber that contained the brine given in [table 4](#). The so-called "brine aging" of all three designed cement plugs was performed for a period of 2 weeks at BHST of 110 °C at 3000 psi. Exemplary cement plug samples are shown in [Figure 1](#), right.

**Figure 1—Curing chamber used for CO₂ aging (left) and exemplary photograph of cement plug samples (right).**

Upon completion, all cement plugs were removed from the curing chamber and 5 samples of each design were identified for acquiring dimensions, weights, and photographs for future tracking purposes. From each design, three 1" by 2" plugs and two 2" by 1" pucks were captured for mechanical properties. One sample from each design was defined for μ -CT scan and another one for permeability and porosity testing. The remaining samples were returned to the curing chamber with formation brine for a period of 10-14 days at ambient conditions waiting on the performance data from μ -CT scans, permeability, and porosity testing.

All cement plugs and pucks, from all three cement designs were placed into a stainless-steel sleeve container and each system was separated with stainless-steel plates. The sleeve was then placed into an HTHP oil-based curing chamber. The stainless-steel container was filled with formation brine and was energized using CO₂ for around 30 min while monitoring a pH drop. The pH stabilized after 15 to 20 mins and was recorded to be 5.0-5.2 at ambient conditions. The curing chamber was ramped to BHST of 110 °C on average in 1.5-2 hours and pressured to 4200 psi. The temperature was kept for one week before it was cooled to 29 °C on average in 3 hours while the pressure was maintained within a range of +/-

100 psi difference. After one week at 29 °C, the chamber was heated up again. This cyclic process was repeated for the entire duration of 6-months. Samples were removed at 1-month and 3-months intervals for testing purposes. At the same point in time, the formation brine was re-energized with CO₂. Table 7 provides an overview about the total number of plugs which were generated for aging and characterization at both laboratories.

Table 7—Plugs generated for the study.

Test	System A	System B	System C
Young's Modulus, Poisson Ratio, Compressive Strength	3	3	3
Permeability & Porosity	1	1	1
μ-CT scan	1	1	1
Brazilian (Tensile)	2	2	2
Total needed for testing at service company (1 for each test above in initial state as well as after 1, 3 and 6-months)	28	28	28
Needed for testing at operator	3	3	3
Total	31	31	31

Complementarily, completely cured plugs (96 hours in fresh water followed by 2 weeks in formation brine) were also provided to the TSC for non-cyclic (static) exposure in formation brine (110 °C, 4,200 psi CO₂). The autoclave inside the heating cabinet used at the TSC is shown in Figure 2.



Figure 2—Autoclave inside heating chamber used at the TSC for exposure of cement plugs to CO₂-saturated formation brine.

Results

Appearance

Figure 3 to Figure 8 show photographs of the cement plugs after 2-weeks of curing in formation brine and after exposure to CO₂-saturated formation brine for 6-months with temperature cycling for all three cement systems, respectively.



Figure 3—System A – After 2-week brine cure.



Figure 4—System B – After 2-week brine cure.



Figure 5—System C – After 2-week brine cure.



Figure 6—System A – After 6-months in carbonic acid.



Figure 7—System B – After 6-months in carbonic acid.



Figure 8—System C – After 6-months in carbonic acid.

Dimensions and Weights

Table 8 to Table 10 provide an overview about the dimensions and weights of samples of the three cement systems after base brine curing as well as after 6-months exposure to CO₂-saturated formation brine with temperature cycling.

Table 8—System A dimensions and weights.

Sample	After 2 Week Brine Cure			After 6-months in carbonic acid			Variation / %		
	Weight (g)	Height (in)	Diameter (in)	Weight (g)	Height (in)	Diameter (in)	Weight	Height	Diameter
A.1	50.66	2.0228	1.0122	51.89	2.0193	1.0187	2.43	-0.17	0.64
A.2	49.92	2.0140	1.0037	51.10	2.0290	1.0063	2.36	0.74	0.27
A.3	50.37	2.0160	1.0082	51.33	2.0250	1.0123	1.91	0.45	0.41
A.4	49.83	2.0113	0.9897	50.78	2.0158	0.9952	1.91	0.22	0.56
A.5	50.11	2.0158	1.0062	51.40	2.0190	1.0135	2.57	0.16	0.73
Average	50.18	2.0160	1.0040	51.30	2.0216	1.0092	2.24	0.28	0.52

Table 9—System B dimensions and weights

Sample	After 2 Week Brine Cure			After 6-months in carbonic acid			Variation / %		
	Weight (g)	Height (in)	Diameter (in)	Weight (g)	Height (in)	Diameter (in)	Weight	Height	Diameter
B.1	49.98	2.0155	0.9950	50.78	2.0258	1.0008	1.60	0.51	0.59
B.2	50.2	2.0163	1.0008	51.16	2.0198	1.0103	1.91	0.17	0.95
B.3	50.32	2.0188	1.0083	51.26	2.0288	1.0187	1.87	0.50	1.02
B.4	51.32	2.0238	1.0112	52.20	2.0300	1.0227	1.71	0.31	1.14
B.5	50.68	2.0140	1.0092	51.73	2.0163	1.0222	2.07	0.11	1.28
Average	50.50	2.0177	1.0049	51.43	2.0241	1.0149	1.83	0.32	1.00

Table 10—System C dimensions and weights.

Sample	After 2 Week Brine Cure			After 6-months in carbonic acid			Variation / %		
	Weight (g)	Height (in)	Diameter (in)	Weight (g)	Height (in)	Diameter (in)	Weight	Height	Diameter
C.1	50.65	2.0105	1.0085	51.53	2.0178	1.0102	1.74	0.36	0.17
C.2	50.84	2.0208	1.0133	51.70	2.0220	1.0175	1.69	0.06	0.41
C.3	50.52	2.0163	1.0052	51.54	2.0208	1.0178	2.02	0.22	1.26
C.4	50.76	2.0085	1.0032	51.60	2.0178	1.0100	1.65	0.46	0.68
C.5	50.78	2.0150	1.0080	51.66	2.0200	1.0150	1.73	0.25	0.69
Average	50.71	2.0142	1.0076	51.61	2.0197	1.0141	1.77	0.27	0.64

Mechanical Properties

The testing methodology for mechanical properties is outlined in Appendix. Please note that the plugs were tested with 1000 psi of confining pressure. In the subsequent 5 tables ([Table 11](#) to [Table 15](#)), the results are compiled, whereas the mechanical properties are illustrated in [Figure 9](#) and [Figure 10](#) as a function of time.

Table 11—Mechanical properties after 96-hour cure.

Design	Young's modulus (Mpsi)	Poisson's ratio	Compressive Strength (psi)	Tensile Strength (psi)	TS/CS
System A	2.026	0.230	8974	554	0.062
System B	1.938	0.215	8401	653	0.078
System C	1.869	0.220	7581	586	0.077

Table 12—Mechanical properties after 2-week cure in brine.

Design	Young's modulus (Mpsi)	Poisson's ratio	Compressive Strength (psi)	Tensile Strength (psi)	TS/CS
System A	2.147	0.233	9916	611	0.062
System B	2.141	0.202	9541	513	0.054
System C	2.020	0.217	9107	629	0.069

Table 13—Mechanical properties after 1-month in carbonic acid.

Design	Young's modulus (Mpsi)	Poisson's ratio	Compressive Strength (psi)	Tensile Strength (psi)	TS/CS
System A	2.313	0.252	13272	589	0.044
System B	2.154	0.221	12544	654	0.052
System C	2.108	0.228	13910	735	0.053

Table 14—Mechanical properties after 3-months in carbonic acid.

Design	Young's modulus (Mpsi)	Poisson's ratio	Compressive Strength (psi)	Tensile Strength (psi)	TS/CS
System A	2.308	0.218	14154	Not performed	Not available
System B	2.228	0.254	12425	Not performed	Not available
System C	2.138	0.268	12411	Not performed	Not available

Table 15—Mechanical properties after 6-months in carbonic acid.

Design	Young's modulus (Mpsi)	Poisson's ratio	Compressive Strength (psi)	Tensile Strength (psi)	TS/CS
System A	2.297	0.214	13156	497	0.038
System B	2.211	0.281	11574	638	0.055
System C	2.127	0.317	11109	599	0.054

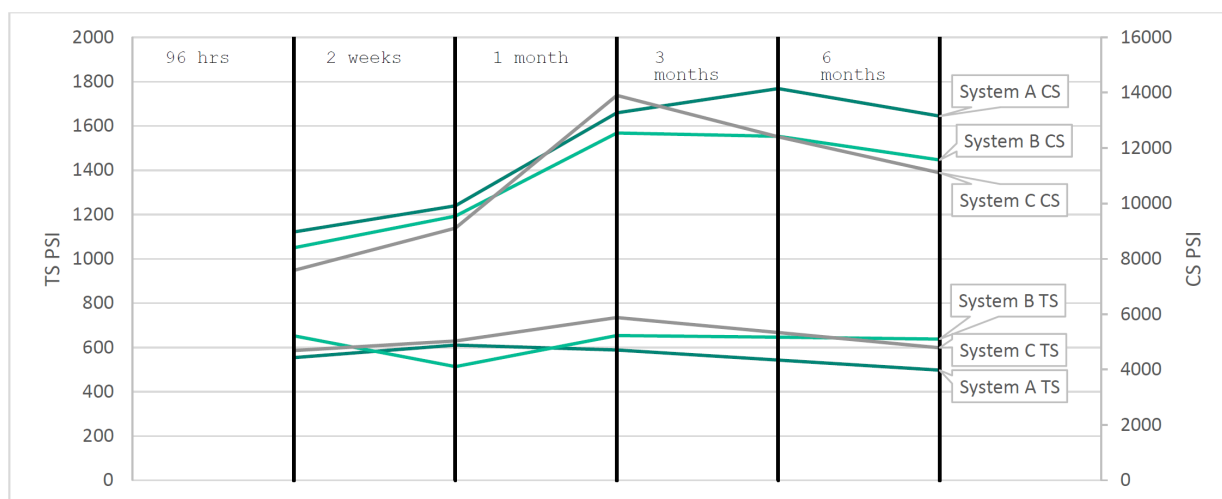


Figure 9—Plotted view of Compressive and Tensile Strengths of the 3 Systems.

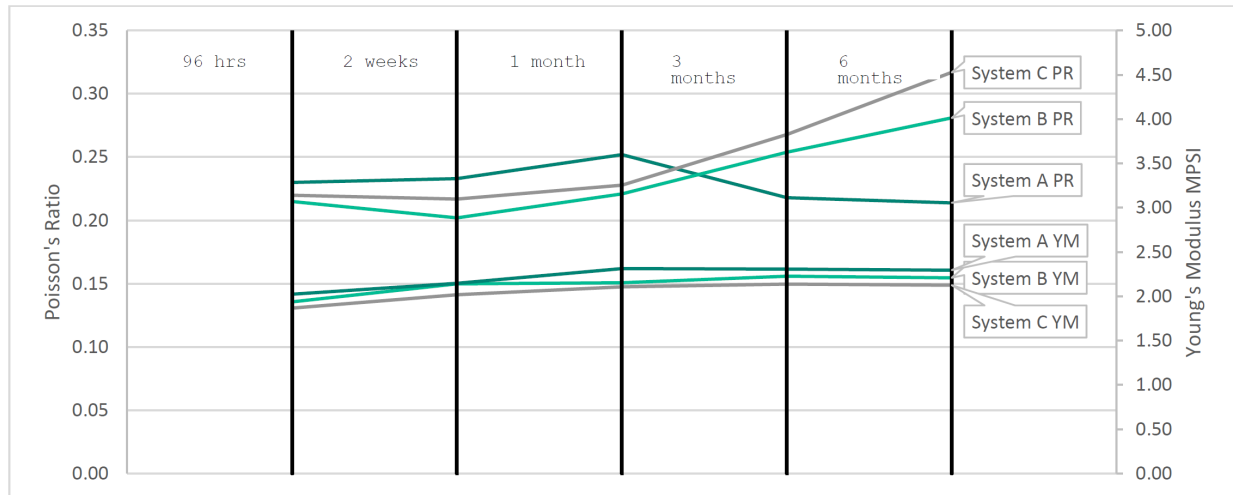


Figure 10—Plotted view of Young's Modulus & Poisson's Ratio of the 3 Systems.

Gas Permeability and Porosity

The testing methodology for gas and porosity measurement are outlined in Appendix. The obtained data and calculated results are summarized in Table 16, whereas the porosity and permeability numbers are illustrated in Figure 11.

Table 16—Gas permeability & porosity results (2W = 2 Weeks in brine, 1M = 1-month in CO₂-saturated formation brine, 6M = 6-months in CO₂-saturated formation brine)

	Test ID	Cure Date	Test Date	Length (cm)	Diameter (cm)	Dry Weight (g)	Pore Volume (mL)	Porosity (%)	Nitrogen Permeability (mD)
2 W	A5	5/30/23	6/6/23	5.080	2.534	43.964	4.026	15.716	<0.0001
	B5	5/30/23	6/7/23	5.092	2.524	43.458	4.226	16.589	<0.0001
	C5	5/30/23	6/7/23	5.058	2.534	44.542	2.492	9.770	<0.0001
1 M	A5	9/12/23	9/20/23	5.094	2.534	40.047	7.651	29.781	<0.0001
	B5	9/12/23	9/20/23	5.099	2.550	39.929	8.698	33.400	<0.0001
	C5	9/12/23	9/20/23	5.098	2.553	43.859	5.564	21.319	<0.0001
6 M	A5	3/25/24	4/10/24	5.105	2.549	42.159	8.290	31.822	0.00104
	B5	3/25/24	4/11/24	5.135	2.558	42.317	7.539	28.57	0.00131
	C5	3/25/24	4/12/24	5.093	2.545	43.768	6.060	23.39	0.00132

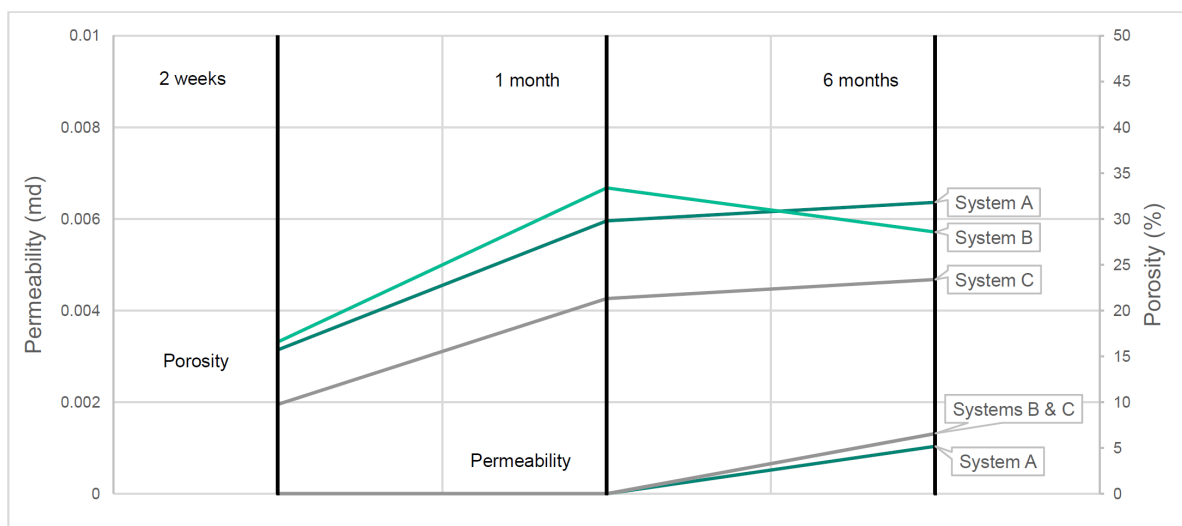


Figure 11—Plotted view of Porosity and N2 Permeability Results.

μ -CT Scan

The complete μ -CT scan settings and results are found in Appendix. This section provides a summary of the results only.

System A. After 2 weeks of curing in formation brine, some cracks show up in the 2D slices with the current settings of porosity analysis partially revealing the crack. Measurements of the crack (width and length) are taken at various locations. The maximum length and width are 26 and 0.14 mm, respectively. Several cracks and inclusion anomalies are visible across the part volume after 6-months of exposure to CO₂-saturated formation brine. It shows one main crack with an approximate length of 26 mm and 0.34 mm width. A higher density is observed within the main crack. Several secondary cracks are observed, too. The corresponding μ -CT scans are shown in Figure 12 showing the sealing of the crack by self-healing precipitate after CO₂-saturated brine exposure.

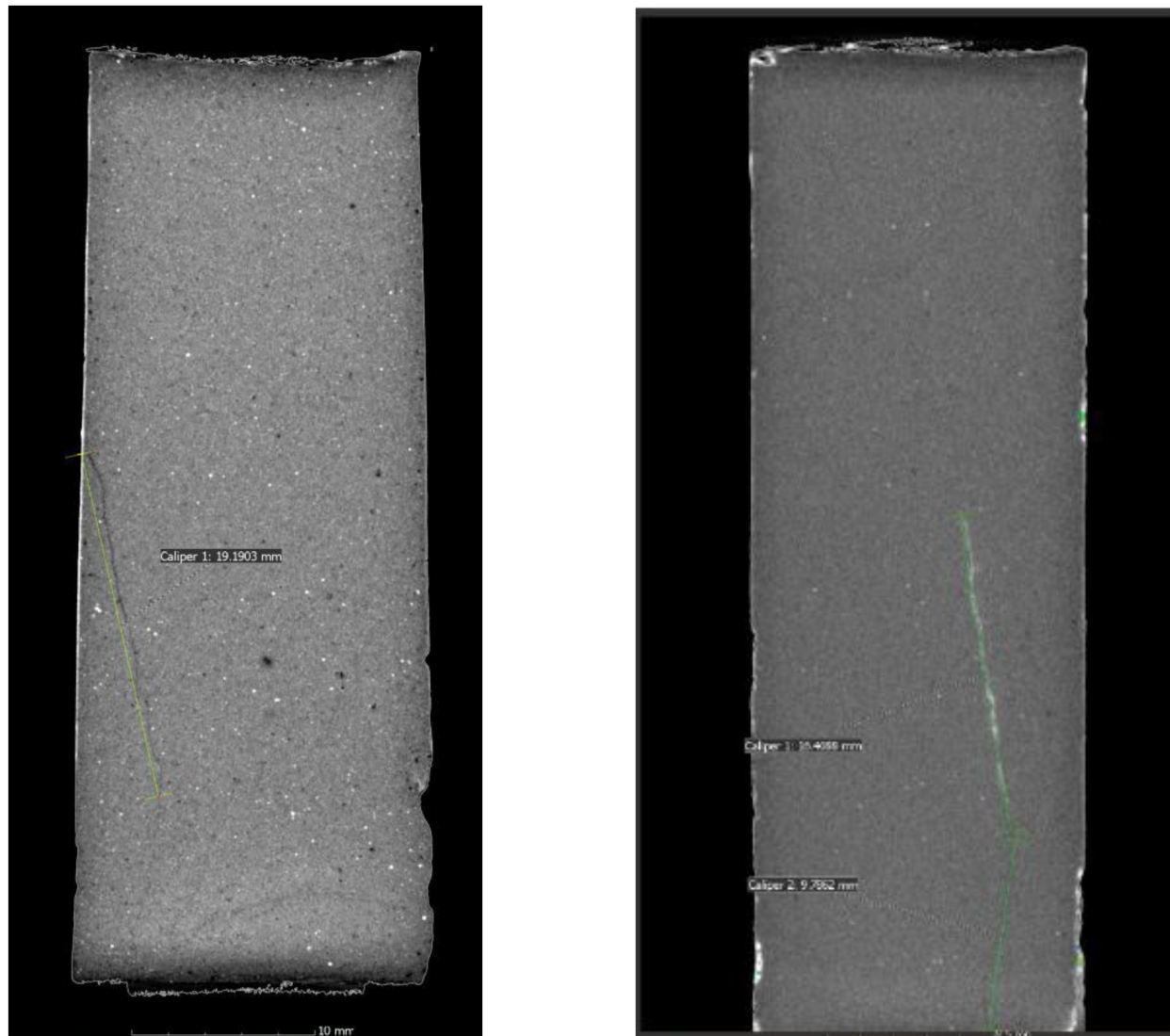


Figure 12— μ -CT scans of System A plugs after 2 weeks curing in formation brine (left) and 6-months exposure to CO_2 -saturated formation brine (right).

System B. The plugs of system B after 2 weeks curing in formation brine show cracks in the 2D slices, whereas the applied settings of porosity analysis do not reveal the crack. Measurements of the crack were taken at various locations with maximum length to be 42 mm and maximum width to be 0.11 mm. After 6-months exposure to CO_2 -saturated formation brine, several cracks and inclusion anomalies are visible across the analyzed volume. It shows one main crack with an approximate length of 36 mm and 0.21 mm width. A higher density is observed within the main crack. Several secondary cracks are observed. The corresponding μ -CT scans are shown in [Figure 13](#).

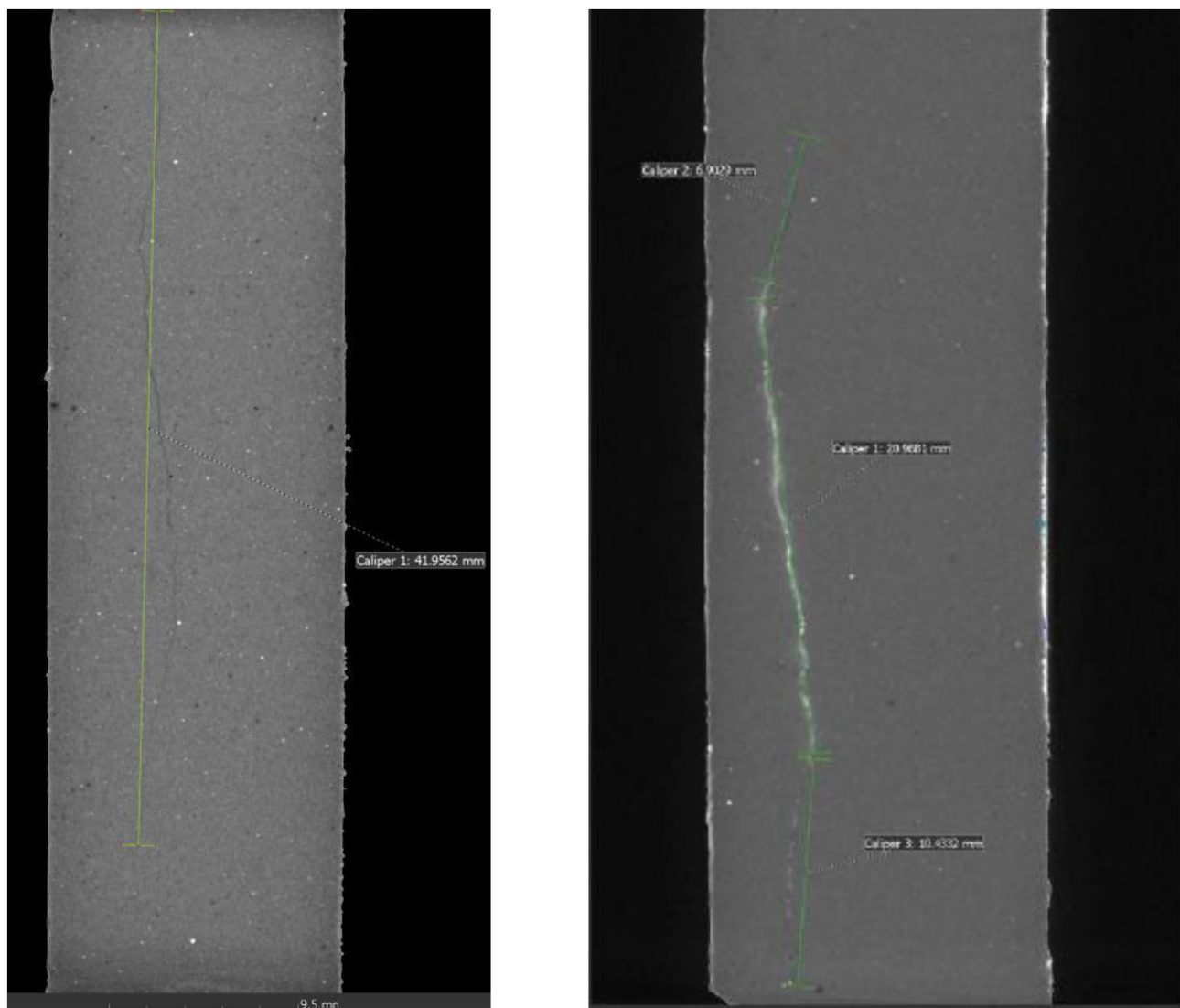


Figure 13— μ -CT scans of System B plugs after 2 weeks curing in formation brine (left) and 6-months exposure to CO_2 -saturated formation brine (right).

System C. Cracks show up in the 2D slices after 2 weeks of curing in formation brine. However, the current settings of porosity analysis do not reveal the crack. Measurement of the crack at various locations results in maximum length of 37 mm and width of 0.11 mm. After 6-months of exposure to CO_2 -saturated formation brine, several cracks and inclusion anomalies are visible across the analyzed volume, it shows a main crack with an approximate length and width of 32 mm and 0.26 mm, respectively. A higher density is observed within the main crack. Several secondary cracks are observed. The corresponding μ -CT scans are shown in Figure 14.

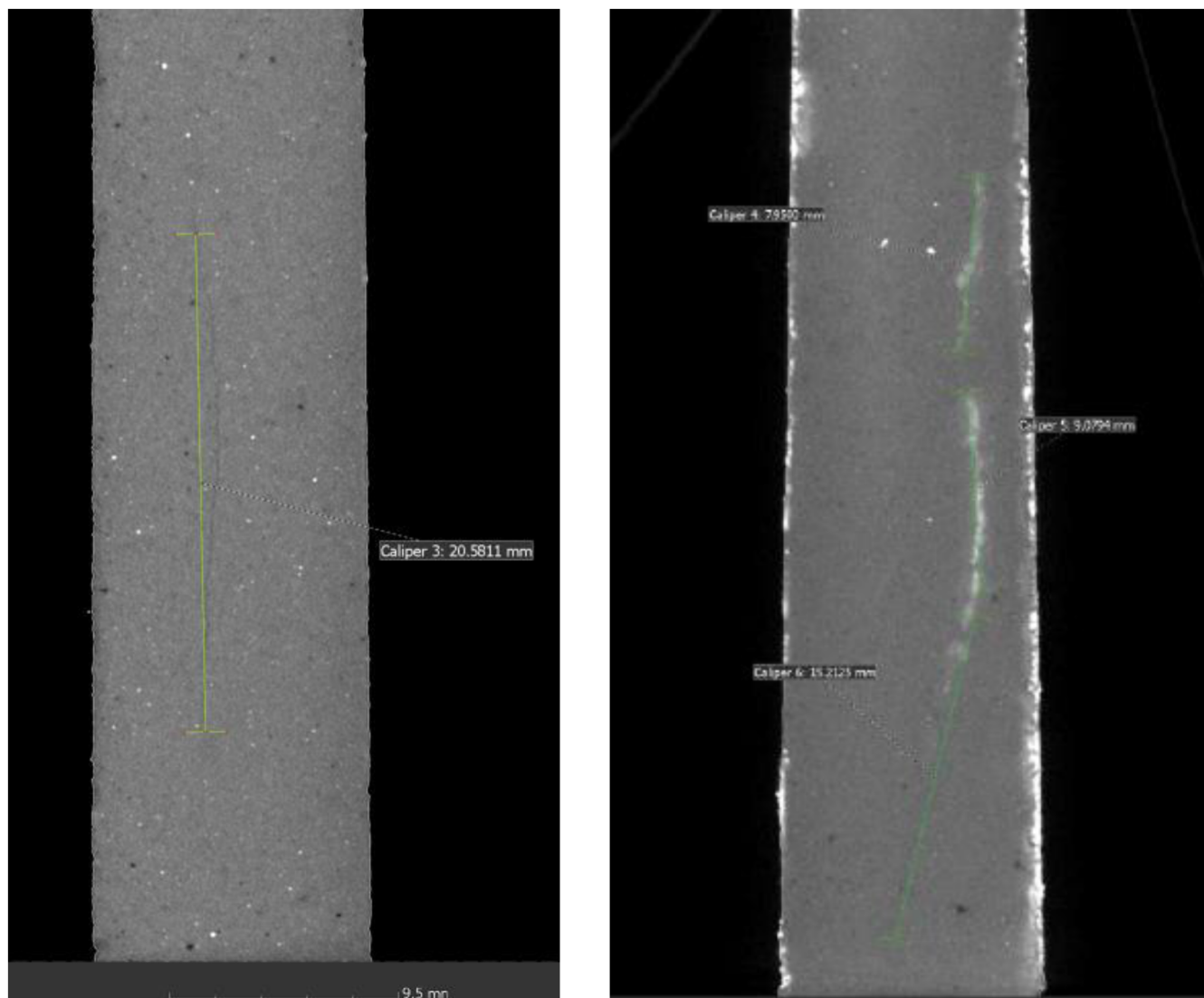


Figure 14— μ -CT scans of System C plugs after 2 weeks curing in formation brine (left) and 6-months exposure to CO_2 -saturated formation brine (right).

Cyclic vs. Static Aging Comparison

The obtained images allow to conclude that after cyclic CO_2 -aging for the period of 1-month, practically no visual changes can be monitored at the surface or the interior of the plugs regardless of the cement slurry formulation. This can be seen on magnified images shown in [Figure 15](#). However, the aging conditions at the TSC (constant high pressure and temperature) already initiate carbonation of the Portlandite in the μm range which is visible in the scans of System A, System B and System C. Magnification shows a decreasing trend of reaction going from System A to System B to System C at the TSC ([Figure 16](#)).

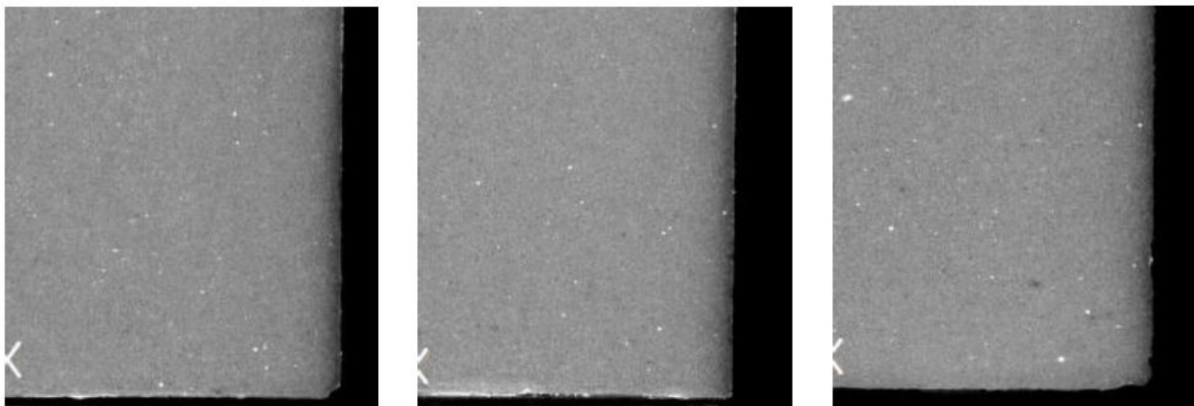


Figure 15—Magnified comparison of the surface-near regio of System A (left), System B (middle) and System C (right) after 1-month cyclic CO₂-aging.

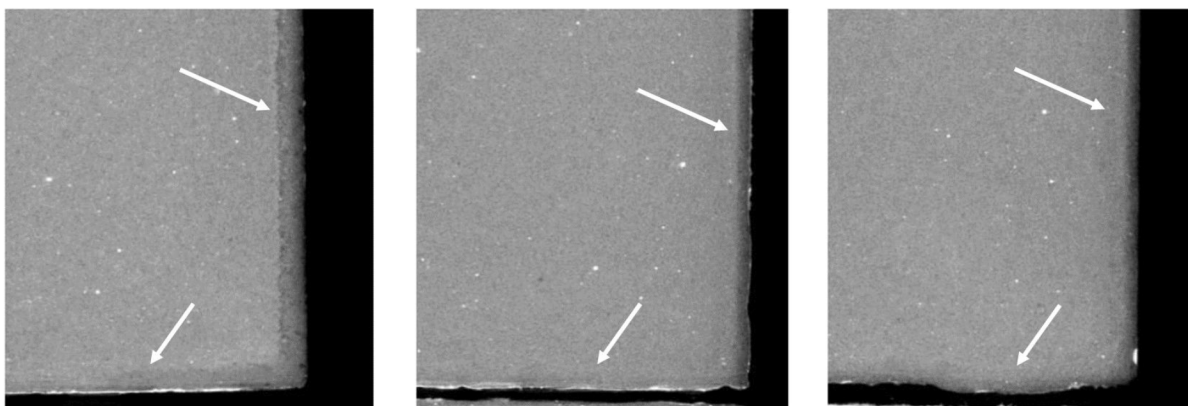


Figure 16—Magnified comparison of the surface-near regio of System A (left), System B (middle) and System C (right) after 1-month static CO₂-aging at the TSC. Arrows indicate the front of carbonation.

Upon extension of the CO₂-exposure time to 3-months, now the cyclically aged samples of System A show first signs of carbonation at their surface, whereas Systems B and C still appear to be unaltered (Figure 17).

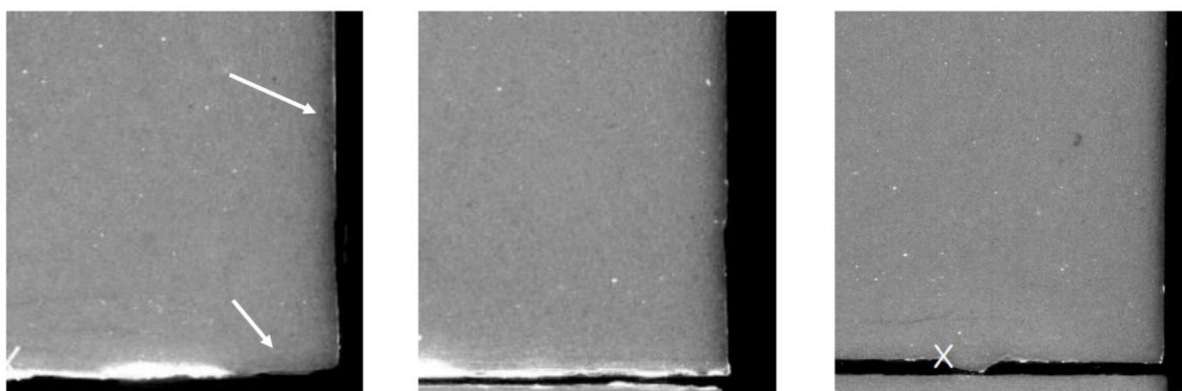


Figure 17—Magnified comparison of the surface-near regio of System A (left), System B (middle) and System C (right) after 3-months cyclic CO₂-aging. Arrows indicate the front of carbonation.

After 3-months aging (static conditions), the magnified scans show, in alignment with the 1-month-aging outcome, again a decreasing trend of reaction (see Figure 18) going from System A to System B to System C.

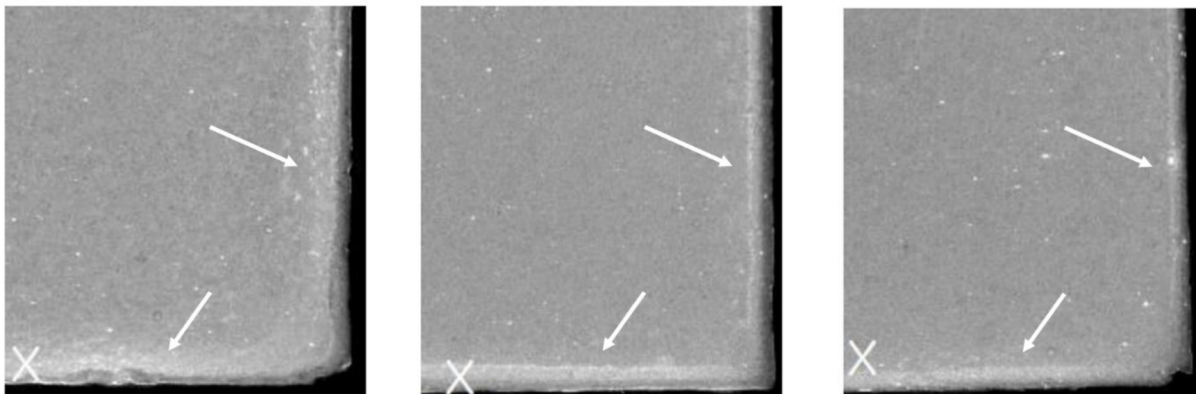


Figure 18—Magnified comparison of the surface-near regio of System A (left), System B (middle) and System C (right) after 3-months static CO₂-aging. Arrows indicate the front of carbonation.

The exposure to CO₂-saturated brine under cyclic conditions for 6-months does not cause any significant changes to the appearance of the plugs compared to their state after 3-months (see magnifications in [Figure 19](#)). However, at the constant (worst-case) conditions, the visual difference in performance of the three systems becomes evident ([Figure 20](#)).

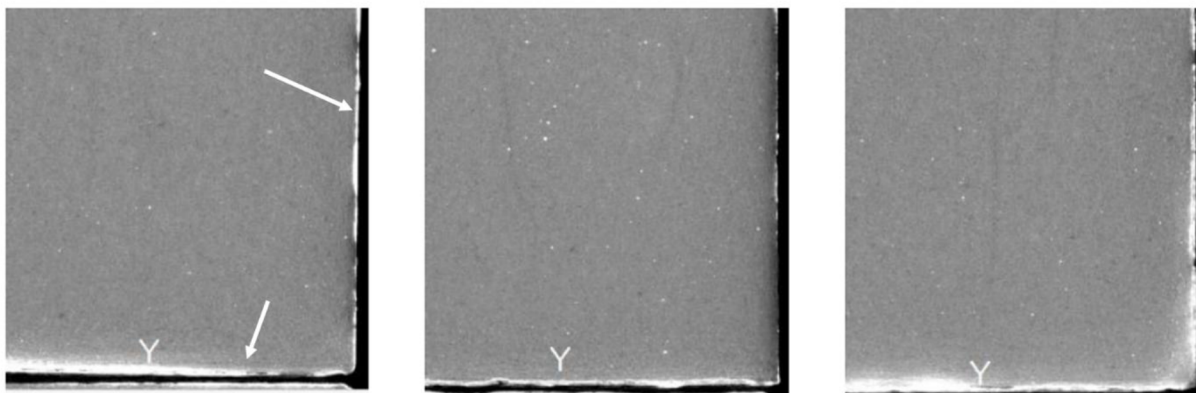


Figure 19—Magnified comparison of the surface-near regio of System A (left), System B (middle) and System C (right) after 6-months cyclic CO₂-aging. Arrows indicate the front of carbonation.

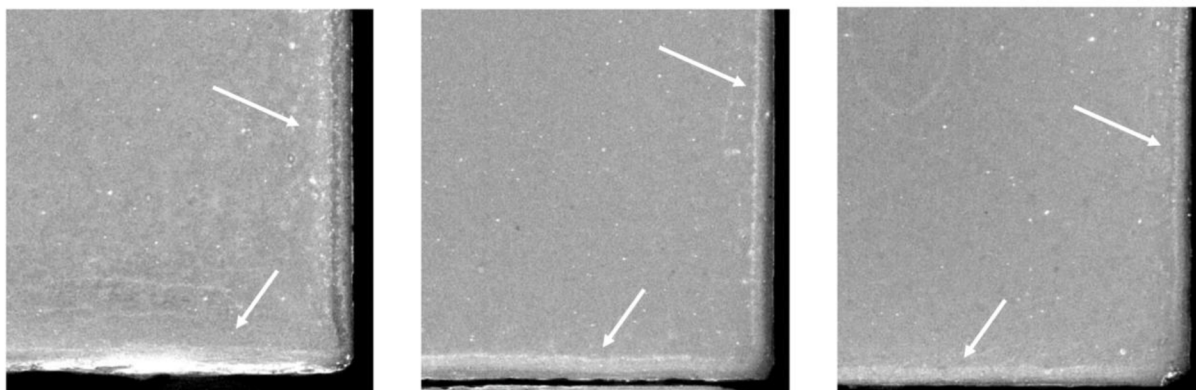


Figure 20—Magnified comparison of the surface-near regio of System A (left), System B (middle) and System C (right) after 6-months static CO₂-aging. Arrows indicate the front of carbonation.

The samples which were aged statically show basically a similar trend with the highest decline in compressive strength (CS) already after one month for System A ([Figure 21](#)). The other two systems appear

to be more resistant towards CO₂-saturated brine even under the harsher static test conditions. Please note that no numbers for 3-months aging are available as these plugs were put into the autoclave again after 3-months and corresponding micro-CT scanning for another 3-months (= 6-months in total).

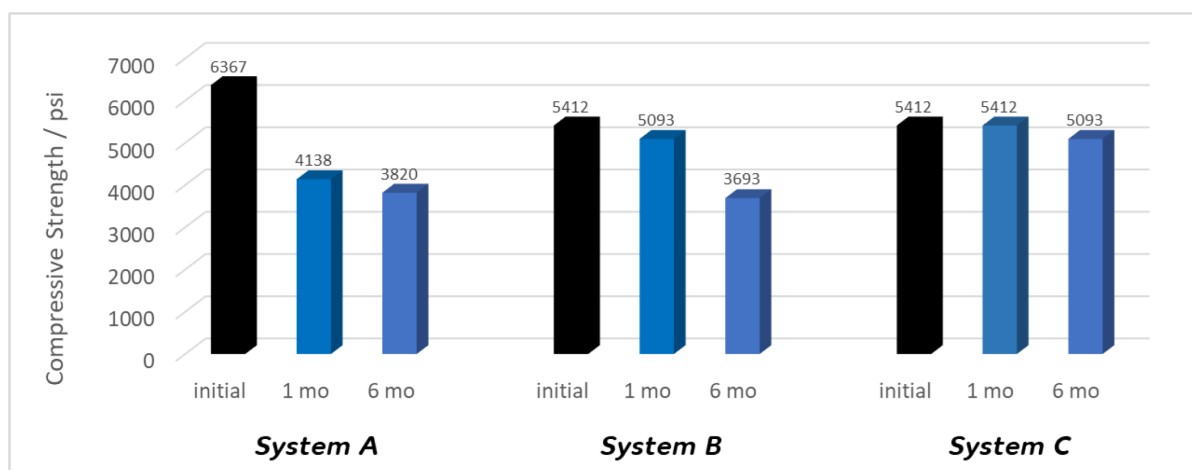


Figure 21—Compressive Strength of System A (left), System B (middle) and System C (right) initial vs. after 1- and 6-months static CO₂-aging.

Discussion

Conventional (Reference Case)

The conventional cement design testing results below were not part of the scope of testing for this study but have been added to be used for comparison purposes against the designs with an estimated enhanced carbonic acid resistance (systems A, B, C). The mechanical properties of this conventional 1.9 SG cement slurry (non-tight Class G cement + 40% Silica bwoc) are compiled in Table 17. The samples were cured at 95 °C and 2100 psi for 96 hrs before being exposed to carbonic acid for 3-months. The carbonated fresh water was re-energized every 2 weeks.

Table 17—Mechanical properties of conventional cement slurry design.

Parameter	Units	96 hrs.	3 M	%
Young's Modulus	Mpsi	1.4	2.49	78
Poisson's Ratio	-	0.26	0.19	-27
Compressive Strength	psi	7658	9172	20
Tensile Strength	psi	599	408	-32

With the same NCS scenario boundary conditions outlined in the introduction the simulation output using the wellbore stress software shown in Figure 22 shows this conventional design would fail radially, an increase in tensile strength (TS) of around 100 psi would have been required to pass under the maximum pressure and temperature deltas.

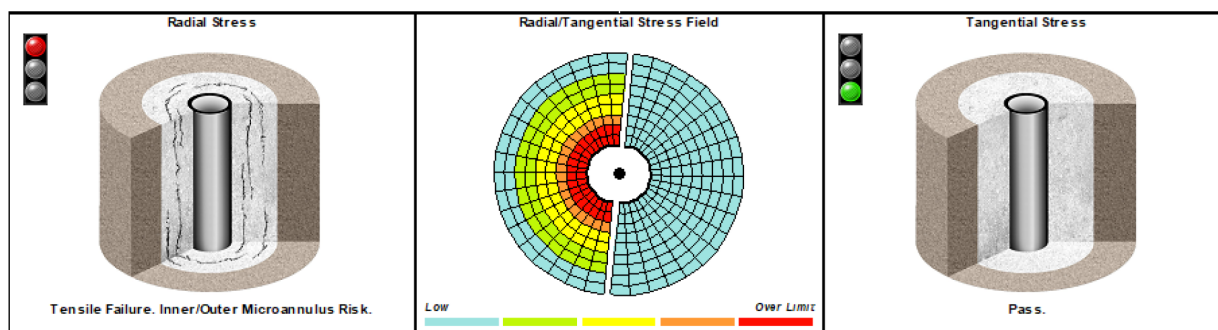


Figure 22—Conventional (Reference) Simulation Output

System A. Comparing Table 17 and Table 18 only in the way the trend of the mechanical properties are relatively affected after 3-months of CO₂-saturated brine exposure, there is no direct comparison because the results are from two different slurry designs, conditions and carbonated fluids.

Table 18—System A mechanical properties of conventional cement slurry design after 2 weeks formation brine, 1-, 3- and 6-months CO₂-saturated brine exposure. The samples were cured at 110 °C and 4200 psi. The carbonated brine was re-energized after 1- and 3-months. The 3-months TS values were interpolated.

Parameter	Units	2 W	1 M	3 M	6 M	2 W / 1 M %	1 M / 6 M %
Young's Modulus	Mpsi	2.147	2.313	2.308	2.297	8	-1
Poisson's Ratio	-	0.233	0.252	0.218	0.214	8	-15
Compressive Strength	Psi	9916	13272	14154	13156	34	-1
Tensile Strength	Psi	611	589	543	497	-4	-16

Both conventional and system A designs show an overall increase in YM and CS, and an overall decrease in PR and TS, which indicates the tendency to a brittle material. The amount of increase/decrease is significantly less for the system A design when compared to the conventional one. Concluding, system A is more resistant to carbonic acid exposure.

Comparing the 2-week non-exposed to a 1-month carbonic acid, results show that there are some changes in the properties with the compressive strength increase being the most significant which is as expected as CS would increase with curing time. The overall change in properties seen in 1-month to 6-months is minimal with regards to YM and CS, while the PR & TS show a more moderate change. The PR reduction can be seen as a benefit, while the TS reduction could have a negative impact on the resistance of the cement downhole to imparted mechanical stresses.

There is an increase in porosity as seen in Table 16 after the 1-month exposure but continued exposure to carbonic acid does not result in a significant change in the porosity results. It is fair to conclude that once the cement is exposed to carbonic acid, a new baseline is created. With regards to the permeability there is a change from the 1-month and 6-months results, while the results are still within the criteria set in Table 2 it is unknown if the trend would continue without extending the exposure period even further for analysis.

The simulation output using the wellbore stress software shown in Figure 23 shows System A improves the resistance towards radial stresses compared to the conventional design and is under the failure threshold.

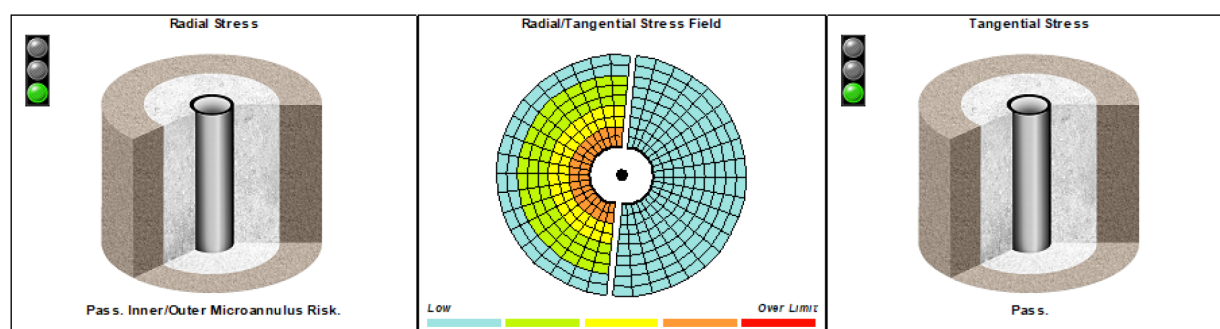


Figure 23—System A Simulation Output

System B. Table 19 shows the Mechanical properties of System B. System B contains an additive which is supposed to achieve better mechanical properties to better resist the potential mechanical stresses imparted on the cement during the life of the well. This additive gives conventional cement enhanced mechanical properties, in particular, tensile strength.

Table 19—System B mechanical properties of conventional cement slurry design after 2 weeks formation brine, 1-, 3- and 6-months CO₂-saturated brine exposure. The samples were cured at 110 °C and 4200 psi. The carbonated brine was re-energized after 1- and 3-months.

Parameter	Units	2 W	1 M	6 M	2 W / 1 M %	1 M / 6 M %
Young's Modulus	Mpsi	2.141	2.154	2.211	1	3
Poisson's Ratio	-	0.202	0.221	0.281	9	27
Compressive Strength	Psi	9541	12544	11574	31	-8
Tensile Strength	Psi	513	654	638	27	-2

Comparing the 2-week non-exposed to a 1-month carbonic acid, an increase in PR, CS & TS is observed. Comparing the results with the numbers of System A as shown in Table 18, the tensile strength increase of System B shows the benefit of the flexible additives being added to System A.

The overall change in properties seen in 1-month to 6-months is minimal apart from the PR. We do not see the same reduction in TS as seen in System A, while CS has decreased and the CS/TS ratio is improved compared to System A.

Like in System A, there is an increase in porosity as seen in Table 16 after the 1-month exposure, but continued exposure to carbonic acid does not result in a significant change in the porosity results. As mentioned before, this leads to the observation that once the cement is exposed to carbonic acid, a new baseline is created. With regards to the permeability there is a change from the 1-month and 6-months results, while the results are still within the criteria set in Table 2 it is unknown if the trend would continue without extending the exposure period even further for analysis.

The simulation output using the wellbore stress software shown in Figure 24 shows that the flexible materials added to System B further improves the resistance towards radial stresses compared to the conventional design & System A.

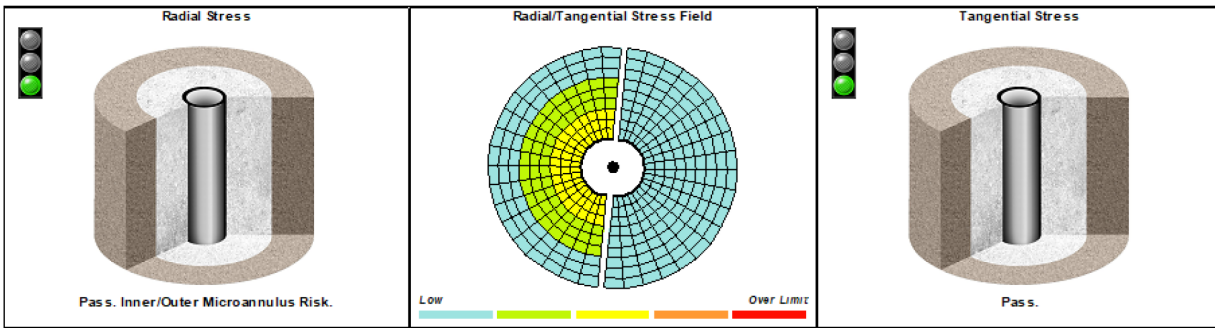


Figure 24—System B Simulation Output

System C. Table 20 shows the mechanical properties of System C which is System B with added Latex. The latter was added to investigate the additional benefits of Latex. Latex is known to reduce the permeability of a slurry design therefore it could show increased resistance to carbonic acid exposure, as shown in Figure 18 & Figure 20, the addition of latex mitigates the delineation of the carbonation front.

Table 20—System C mechanical properties of conventional cement slurry design after 2 weeks formation brine, 1-, 3- and 6-months CO₂-saturated brine exposure. The carbonated brine was re-energized after 1- and 3-months.

Parameter	Units	2 W	1 M	6 M	2 W / 1 M %	1 M / 6 M %
Young's Modulus	Mpsi	2.020	2.108	2.127	4	1
Poisson's Ratio	-	0.217	0.228	0.317	5	39
Compressive Strength	Psi	9107	13910	11109	53	-20
Tensile Strength	Psi	629	735	599	17	-19

Comparing the 2-weeks non-exposed to a 1-month carbonic acid aged sample, we observe an increase across the board. Comparing the results with Systems A and B in Table 18 and Table 19, System C has the highest increase in CS but shows less increase in TS compared to System B. The YM and PR changes are in the range of the two other systems.

The overall change in properties seen in 1-month to 6-months is more significant compared to the other two systems, with the highest relative decreases in both CS and TS, further evaluation would be required to determine the cause of the reduction. Overall keeping this in mind the CS/TS ratio is still better than system A and is comparable to system B.

Like the other two systems there is an increase in porosity as seen in Table 16 after the 1-month exposure but continued exposure to carbonic acid does not result in a significant change in the porosity results. It is observed that once the cement is exposed to carbonic acid, a new baseline is created. System C has the lowest porosity results as expected due to the addition of Latex, to be mentioned is that the relative increase from 2-weeks to 1-month is in line with the other systems.

With regards to the permeability there is a change from the 1-month and 6-months results, while the results are still within the criteria set in table 2 it is unknown if the trend would continue without extending the exposure period even further for analysis.

The simulation output using the wellbore stress software shown in Figure 25 shows that the addition of Latex System C shows similar, with small differences in the raw data output, resistance towards radial stresses as expected compared based on the mechanical properties to System B.

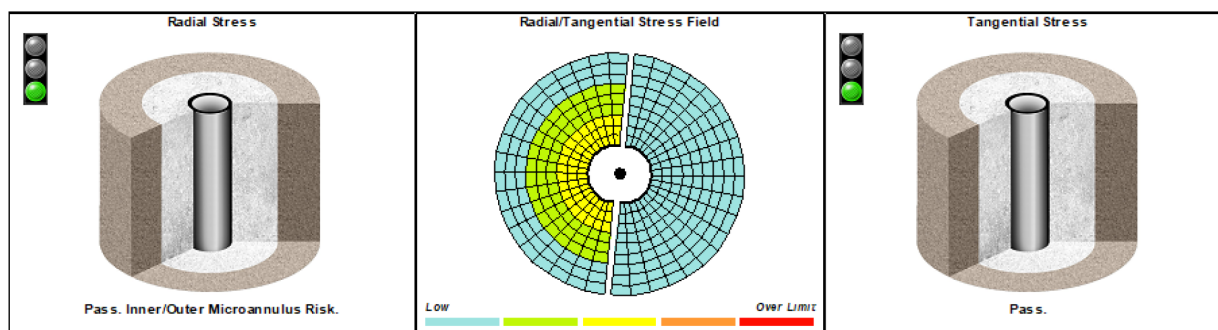


Figure 25—System C Simulation Output

Summary and Conclusion

For the CCS injector wells, the service company and the client jointly qualified the optimum design to withstand the conditions the cement would be exposed to. Referencing the pre-set acceptance criteria and the available study data, basically all three systems A, B and C can be rated as "passed":

The addition of a dedicated component as part of System B and C improves the resistance to carbonation significantly, whereas supplementary Latex only provides a minor extra benefit (visually/mechanically).

The different test conditions (cyclic vs. static) have shown a significant impact on the degree of reaction of the Portland-based cement systems during exposure to CO₂-saturated brine. Basically, the cyclic conditions (ramping pressure and temperature up and down between maximum and minimum) are less harsh on the cement compared to the constant maximum pressure and temperature kept constant in the autoclaves. The realistically slow changes of the conditions do not impose any additional stress on the samples. The average partial pressure of CO₂ appears to be the dominant factor. In other words, keeping the temperature at maximum and not cooling or cycling is driving more reaction resulting in slightly poorer results. Another factor to account for during CO₂ injection is that during cooling the casing could contract which causes debonding of the cement, therefore it is recommended to have a flexible cement design. The testing methodology employed for this study does not accurately portray these phenomena.

Summarizing, System B provides the best overall performance with regards to resistance towards CO₂, operational flexibility and environmental rating and has, thus, been recommended for 9 5/8" Production Liner Casing in the injector wells.

Acknowledgements

The authors would like to thank Baker Hughes and Harbour Energy for their permission to publish this work. Furthermore, special thanks are dedicated to Sarah Lietzmann, Vitali Penner, Till Bollermann, Rolando Lew, Fedymar Pereira and Thomas Gabel as well as all other colleagues involved from both laboratories contributing to this publication. We would also like to thank our license partner for the permission to publish this paper.

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Appendix

Mechanical Properties Testing

Testing procedures and apparatus closely followed ASTM D 7012-07 recommended practices. Confined tests were performed on a GCTS™ hydraulic test frame. Cement samples were sleeved in 0.017-inch-thick polyolefin heat-shrink tubing and mounted between two steel plates. The spherical seat of the upper platen contacted an internal pressure-compensated load cell (100-thousand-pound load capacity) through which the axial stress was applied to the top of the sample.

Two LVDT's were positioned parallel to the length of the cement sample (and internal to the pressure vessel) and used to measure the change in sample length. A circumferential displacement gauge was wrapped around the sleeve and used to measure the change in circumference of the sample. Confining stress was supplied by hydraulic oil that fills the vessel and pressurized using a programmable intensifier pump. Tests were conducted under drained conditions by keeping the pore pressure lines open to atmospheric pressure. Testing is conducted at room temperature (72 °F).

The stress path of the confined tests consisted of an initial isostatic ramp to 1000 psi confining stress at a rate of 250 psi/minute, after which the state of isostatic stress was held constant to allow time for the axial and radial strains to equilibrate. The deviatoric axial cycle is ramped at a rate of 0.1% axial strain per minute until specimen failure is achieved. Deviatoric axial stress is then ramped down.

The axial deviatoric stress was calculated from the ratio of axial force to sample cross-sectional area (corrected for dilation). The uncorrected axial strain was calculated from the ratio of the average displacements of the two axial LVDT's to the initial sample length.

The total axial deformation included some deformation from the steel plates to which the axial LVDT rings were held in place. The axial strain was corrected by subtracting out the effect of the plates using the relationship:

$$\Delta X_c = \Delta X_m - f(F_d) \quad (\text{I-1})$$

ΔX_m is the measured axial displacement. $f(F_d)$ a sixth-order polynomial fit of the platen-platen direct contact displacement-load curve and represents the displacement of the platens, alone. F_d is the axial deviatoric force on the platens.

The corrected axial strain was then calculated from the ratio:

$$\Delta \varepsilon_c = \frac{\Delta X_c}{L} \quad (\text{I-2})$$

L is the initial sample length.

Young's modulus (E) was calculated from a linear least-square regression of the increasing axial stress versus axial strain curve between 20% and 40% of the peak strength.

$$E = \frac{\Delta \sigma}{\Delta \varepsilon_c} \quad (\text{I-3})$$

The radial strain was calculated from the expression:

$$\varepsilon_r = -\frac{\gamma \Delta C}{\pi D} \quad (\text{I-4})$$

ΔC is the change in circumference of the sample, which was directly measured by the circumferential LVDT. Note that an increase in circumference (i.e., positive ΔC) produces a negative radial strain. D is the sample's initial diameter. γ is a geometrical correction factor required when using chain-type gauges that measure chord length and not arc length. Poisson's Ratio was calculated from the linear least square regression of the radial versus axial strain curve.

Gas Permeability and Porosity Test Procedure

An Ultrapore 300 Porosimeter is used to measure each sample's basic properties. The Porosimeter utilizes Boyle's Gas Law to calculate the grain volume of the sample. The grain density is also calculated based on the samples dry weight. Using the length and diameter of the core, the bulk volume is calculated which allows for the calculation of the pore volume and porosity.

Porosity Procedure:

1. The sample is placed into the matrix cup and the empty space filled with the calibrated disks. The matrix cup is loaded into the porosimeter.
2. The length, diameter, and dry weight are entered into the software and the grain volume measure is started.
3. The Porosimeter then calculates all the basic core properties for the sample.
4. Sample is unloaded.

Gas Permeability Procedure:

1. The core is loaded into a hydrostatic core holder and a confining pressure of 1500 psi is applied.
2. At ambient temperature nitrogen is injected through the core at a constant differential pressure of 600 psi and the gas output flowrate is monitored over time.
3. Using Boyle's Gas Law, the gas flow rate at internal pore pressure (reservoir pressure) is calculated and the permeability of the sample to nitrogen is calculated.
4. If the permeability is below 0.0001 mD no true measurement can be made and < 0.0001 mD will be reported.

Definition of Permeability – Based on Darcy's Law which shows that the fluid rate through a porous medium is directly proportional to the pressure gradient in the fluid and inversely proportional to the fluid viscosity.

$$Q = -\frac{k}{\mu L} \Delta P \cdot A \quad (\text{I-5})$$

Is Darcy's Law Equation where:

Q = Rate of flow

k = permeability

μ = dynamic viscosity

L = length of sample in units

ΔP = total pressure drop

A = area

Micro-CT Scanning

Micro-CT scanning was performed using a V|TOME|X M-300/180 with subsequent reconstruction and analysis using software DATOS|X 2.7. An exemplary photograph of a mounted sample is shown in [figure 3](#). The 3D images in the cured state were used to qualitatively assess the cement homogeneity and uniformity for each formulation and potential presence of defects, such as fractures. The plugs were re-scanned in one or more of these lab-treated states, in which case the after-state 3D image was spatially aligned with the corresponding before-state image for quantitative analysis.

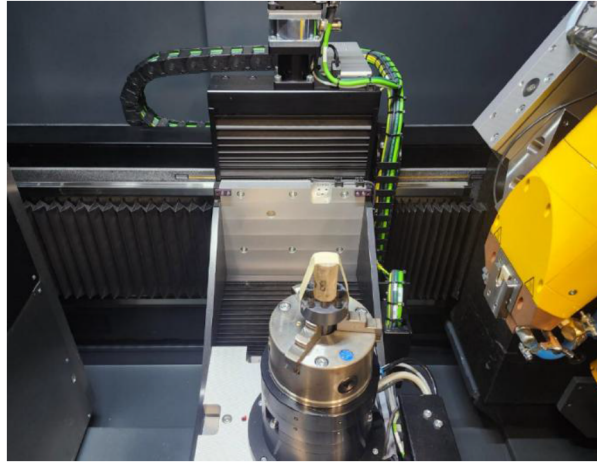


Figure 26—System A – After 2-week brine cure.