EFFECTIVE AVALON FORMATION PRODUCTION; DATA DRIVEN TOTAL SYSTEMS ANALYSIS LEADS TO SUCCESSFUL TREATMENT OF SEVERE CALCIUM CARBONATE SCALE; IN THE DELAWARE BASIN AVALON FORMATION

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ABSTRACT

There has been a recent shift in the Permian across unconventional frac targets in the Delaware Basin stacked play, shifting to shallower formations. As a result, Avalon targets are becoming more common. When comparing key scale risk drivers such as brine compositions, mol% CO2 and H2S of the Avalon formation to more traditional targets such as the Wolfcamp and 2nd & 3rd Bone Springs, not only does the Avalon present its own unique scaling challenge, but the commingling of these formations can present much greater scale control and asset integrity challenges. Previous work has highlighted the Avalon formation has a high natural potential for carbonate scale precipitation, which aligns with field history presented here. These unique challenges will play a part in the next wave of formation-based proactive chemical treatment strategies across upstream, midstream and water disposal systems.

Here we present a case of severe carbonate surface scaling from Avalon formation brines, with a discussion on common issues encountered by adding Avalon production to existing fields. The operator was experiencing calcium carbonate scaling on flowlines, water legs of separators and equalizing lines between water tanks every 3 to 4 months. The operator had to choose between using heater treaters in winter to sell oil or scaling off the heaters. Incumbent service companies had successfully controlled downhole scale but could not control the surface scale issues.

A total systems analysis including field analysis, scale modeling, 21 produced fluid chemical compatibility experiments run across 11 different scale inhibitors, minimum effective dosage (MED) identification through 119 NACE static/synthetic brine and Dynamic Scale Loop (DSL) testing was performed to identify a solution.

The solution highlighted in this paper resulted in zero facility scale-offs (26 month treatment period to date of publication), use of heater treaters in winter to sell oil, and operational efficiency gains in reduced manpower for cleanouts. Additionally, the ability to now commingle high-risk brines at central tank batteries allowed for the decommission of small satellite facilities previously used to isolate the highest scale risk brines.

The Avalon is not a new target but is projected to become more common in the future. The recent shift has implications to change how, where, and why we treat for carbonate scale in the Delaware Basin.

INTRODUCTION

A producer in the Delaware Basin, a sub-basin of the larger Permian Basin, was having frequent carbonate scale issues with a subset of wells producing from the Avalon Formation. Scale issues were historically encountered downhole and at surface since the wells were brought online. Prior to our total systems analysis, carbonate scale issues were so frequent, the operator had a downhole squeeze program, supplemental downhole continuous scale and corrosion program and an additional continuous scale treatment at surface facilities. Facilities still scaled off every 3-4 months despite the robust incumbent scale control program. In winter, the operator had to choose between operating heater treaters at 150-160°F to sell oil or scaling of the heaters, which would then require mechanical remediation. Further, water had to be isolated in smaller commissioned surface facilities to reduce risk of scale forming from mixing with other produced waters. Frequent facility scale-offs and cost of treating was resulting in costly facility cleanouts and increasing cost of operations.

The investigation focused on the surface scale issues as the incumbent squeeze program appeared to be controlling the scale downhole. A total system analysis approach was taken for this operator. The first step was understanding the system followed by a detailed series of scale risk modeling, mixing scenarios and comparative produced brine assessments. This work allowed us to select several fit-for-purpose phosphate ester (PE.), polymer (Ply.) and phosphonate (Ph.) chemistries as potential candidates. Produced fluid compatibility experiments and static bottle synthetic brine experiments shed light on interesting fluid scale inhibitor incompatibilities. Results presented in this paper demonstrate the effects on the resulting MED with and without iron in the tests. Finally, DSL testing was performed to confirm the best product to solve the frequent carbonate scale issues.

Statement of Theory and Definitions

The Permian basin is one of the top producing basins in the world. The Delaware Basin is a sub-basin located within the western half of the greater Permian basin. Over the last decade the Delaware Basin has significantly increased in production with advancements in unconventional frac techniques. The Permian is a complex stacked play of many producing zones with unique characteristics (Bryndzia, L.T. et al. 2022; Gaswirth, S.B. et al. 2016; Gaswirth, S.B. et al. 2018; Hills, J.M., 1984; Montgomery, S. L. 1997a; Montgomery, S. L. 1997b).

The Avalon formation (Figure 1a) north of the New Mexico-Texas state line is the area of interest. Figure1b shows the geographical area of the wells from this case study highlighted in orange. The Avalon formation sits above the 1st, 2nd, and 3rd Bone Springs and Wolfcamp producing intervals (Montgomery, S.L. 1997a). Each producing zone has unique brine characteristics (Table 1) that lend it to having unique downhole untreated flow assurance risk characteristics (Hudson, R. W. et. al. 2022). From previous work, the Avalon is more likely to precipitate carbonate scale solids downhole compared to the more common Wolfcamp and some Bone Springs targets if left untreated (Hudson, R. W. et. al. 2022). If we look at average m-alkalinity and calcium across these producing targets, the Avalon has the greatest average m-alkalinity in the offset waters and in some cases higher calcium content compared to lower reservoirs (Table 1).

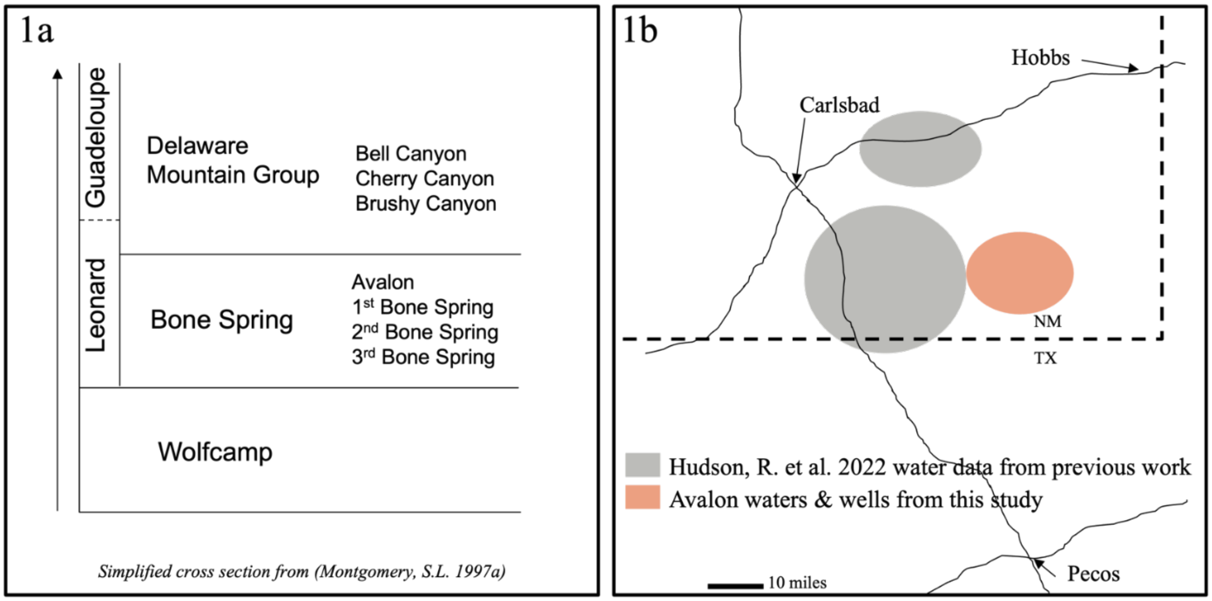


Figure 1 - 1a shows the stratigraphic location of the Avalon formation (Montgomery, S.L. 1997a).
1b Orange field shows geographic area of Avalon waters considered in this study.
Grey area shows the geographic area of waters from previous work (Table 1).

Table 1 - Average water data from offset study area (Hudson, R. W. et. al. 2022) showing the range in brines from neighboring wells (Figure 1b).

	This Study Water Data		Offset Formational Water Data					
Formation	AVALON SHALE		AVALON SHALE		2ND BONE SPRING	3rd BONE SPRING	WOLFCAMP A	WOLFCAMP D
# of waters	32		17		225	22	83	81
	Avg	Min. - Max.	Avg.	Min. - Max.	Avg.	Avg.	Avg.	Avg.
Sodium	(59,936)	29,120 - 71,270	(64,397)	1,750 - 82,300	(58,614)	(38,211)	(33,794)	(34,201)
Potassium	(935)	580 - 1,200	(1,032)	878 - 1,360	(1,178)	(753)	(632)	(554)
Magnesium	(746)	276 - 1,320	(1,195)	346 - 2,520	(1,241)	(759)	(620)	(380)
Calcium	(3,672)	752 - 7,069	(5,381)	1,180 - 9,290	(7,830)	(4,531)	(3,813)	(3,231)
Strontium	(172)	48 - 276	(953)	410 - 1,480	(1,087)	(998)	(928)	(1,028)
Barium	(1.36)	0 - 5.78	(8.86)	0.9 - 19.9	(9.96)	(6.57)	(4.44)	(7.21)

	This Study Water Data		Offset Formational Water Data					
Formation	AVALON SHALE		AVALON SHALE		2ND BONE SPRING	3rd BONE SPRING	WOLFCAMP A	WOLFCAMP D
# of waters	32		17		225	22	83	81
	Avg	Min. - Max.	Avg.	Min. - Max.	Avg.	Avg.	Avg.	Avg.
Iron	(112)	26 - 518	(42.91)	1 - 214	(52.66)	(32.72)	(27.33)	(47.32)
Manganese	(1.4)	0 - 9	(1.16)	0.1 - 4.03	(1.14)	(1.39)	(0.98)	(1.55)
Chlorides	(99,521)	55,060 - 119,356	(111,836)	93,087 - 159,090	(104,244)	(66,262)	(57,382)	(54,590)
Sulfate	(1,937)	220 - 3,600	(433	111 - 2,453	(282)	(210)	(275)	(182)
M Alkalinity	(1,961)	244 - 3,904	(434)	36.6 - 1,220	(173)	(261)	(136)	(164)
TDS	(169,318)	93,402 - 199,714	(185,309)	165,818 - 240,615	(174,909)	(111,959)	(98,140)	(94,631)
Dissolved CO2	(959)	180 - 4,000	(410)	100 - 800	(329)	(238)	(175)	(192)
Dissolved H2S	(14)	0 - 136	(6.0)	0 - 17	(5.4)	(4.4)	(2.2)	(6.6)
Measured pH	(6.17)	5.33 - 7.46	(6.61)	5 - 7.6	(6.65)	(6.81)	(6.89)	(6.97)

Avalon waters from this study located ~10 to ~40 miles east of the offset data set show considerable signs of heterogeneity (Table 1). Average m-alkalinity of study waters is considerably greater at 1,961 mg/l compared to 434 mg/l and average iron is more than double the offset dataset at ~112 mg/l compared to ~43 mg/l. Calcium content is slightly lower with the average study waters at ~3,672 mg/l compared to ~5,381 mg/l. The impact iron can have of the resulting MED and compatibility/performance of scale inhibitors has been well documented over the years from 10 to 100 mg/l (Cushner et al., 1989; Dyer et al., 2000; Graham et al., 2003; Kriel et al., 1994; Lu et al., 2016; Guan et al., 2008; Kan et al., 2008; Marlow et al., 2009; Shen et al., 2011; Zhang et al., 2015; Zhang et al., 2016; Haiping et al. 2016; Spicka et al., 2020). The literature describes the Avalon formation as a sandstone (Montgomery, S.L. 1997a) where later work describes it as dominated by carbonate rich rocks, calcareous pack stones, calcareous mudstones, and finer grained siliciclastic mudstones. (*Stoltz, Dustin J. & Franseen, Evan K., 2015).* Gravity flows within the Avalon formation are also mentioned in the literature. Variability in carbonate geology could potentially explain the heterogeneity observed in wells located ~10 to ~40 miles apart. Avalon waters from this study are different from the offset dataset which already had a known potential to precipitate carbonate downhole. Previous work (Hudson, R. W. et. al. 2022) only looked at solids collected from tubing pulls and did not look at scale risk from surface deposits, which is the focus of this study.

Mole % CO_2 of the study wasters ranges from 2.4% to 14.6% with an average of 12.2% and the measured pH of study waters ranges ~5-7.46. Carbonate scale and severity of resulting precipitation is strongly controlled by the brine chemistry, CO_2 content of the system, pH, temperature, and pressure (Vetter, O. J., and W. A. Farone., 1987; Guan, Hua., 2010). It is well known that as fluids come to surface pressure typically drops, CO_2 breaks out of solution and pH increases in the fluid which can increase the risk of carbonate scale. Further, pH taken in the field after opening a sample port is typically no longer representative of the in-situ pH. This range was considered too large to use in performance testing. Various methods used by various labs with and without pH adjustment among other variables can play a critical role in reported MED determination (Graham, G. M., Collins, I. R., Stalker, R., and I. J. Littlehales., 2022). Further mixing of waters post sample point and inclusion of oil in the models can complicate risk modeling and brine selection when solving surface scale issues (Vetter, O. J., and W. A. Farone., 1987).

METHOD

An extensive brine assessment across all effected wells which mix at surface was performed to facilitate brine selection for performance testing. The goal was to understand a worst case and average MED pre and post mixing by evaluating brines that represented well water and mixed compositions within facilities. To achieve this, SSP 2019 scale modeling was performed to better understand the in-situ pH and scale risks of individual wells and of mixing produced brines within facilities. Trends of increasing risk from downhole to surface were evaluated in hopes to identify where precipitation initiated. Historical waters and new water analyses were considered in the models. Option 0 and gas analysis metered oil, water and gas production was included in the modeling. 128 modeling scenarios were run on 32 individual water analysis. From this modeling work three brines were selected to carry through performance testing.

Produced fluid chemical compatibility experiments were run across 11 different products using freshly produced fluid collected from a well. Products were dosed at 1,000 ppm and in some cases 10,000 ppm in hopes of easily identifying incompatibilities. Bottles were heated at three temperatures (84°F, 120°F & 160°F) to simulate the range of temperatures from flowline/separator to heater treater to water tank. Products were evaluated for changes in emulsion tendency, phase separation, and solids. Acid was added back to determine if solid precipitate was acid soluble, which added in the identification of scale formation or in some cases scale inhibitor chemistry incompatibilities with the brine.

NACE Standard TM0374-2015 style static/synthetic brine experiments were run based on two brines. Iron was not included in these tests, but in-situ pH adjustments were made to align with modeled in-situ pH. Results were determined visually at three temperature nodes (~84°F, 100°F & 160°F) to mimic the system. Acid was added back to determine if solid precipitate was acid soluble, which added in the identification of scale formation or in some cases scale inhibitor chemistry incompatibilities with the brine.

Top performing compatible scale inhibitor chemistries were carried into DSL testing where MED was identified with iron concentrations of 0 mg/l, 50 mg/l and 100 mg/l. A combination of anoxic analog cation and analog anion solutions were mixed at test conditions with set concentrations of scale inhibitors in a 1:1 ratio. DSL conditions were run at 160°F, with a total flow rate of 10 mL/min, scale coil length of 1m, inner diameter of 1mm, pressure of 600psi, pH adjusted using CO2 gas to ~6.5-6.1. Pass fail criteria was set at less than 1psi differential pressure (dp) change over a minimum of 2 times of the blank scaling time.

DATA AND RESULTS

SSP 2019 & In-situ pH Modeling

SSP modeling across the nodes within the system showed an increase in risk at surface conditions for carbonate scale in this system (Figure 2). This increase in risk, correlates with the issues this operator was seeing in the field.

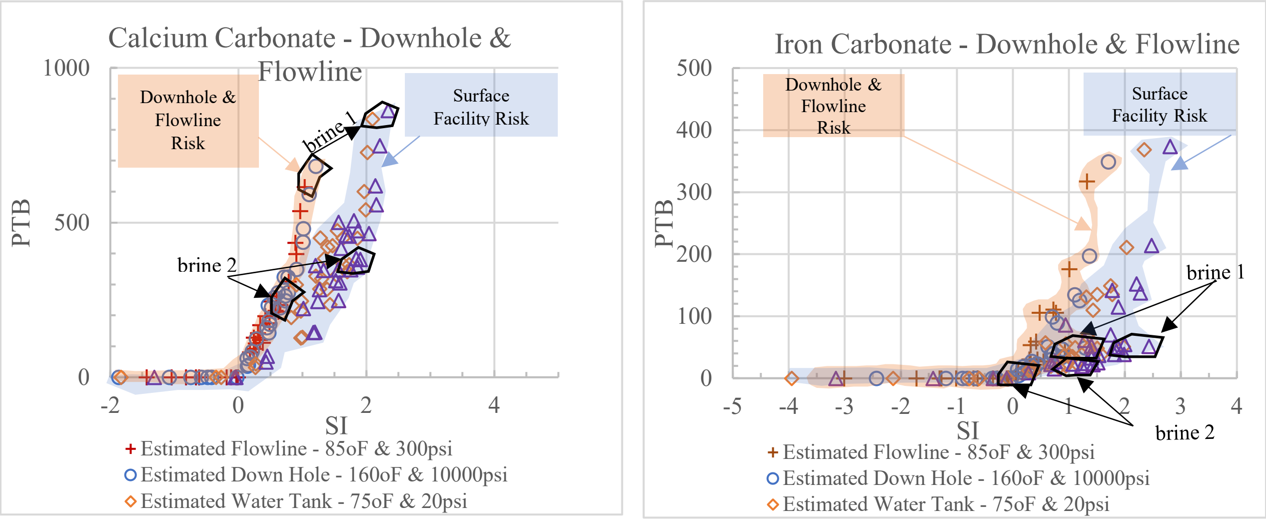


Figure 2—SSP 2019 carbonate scale modeling showing the risk increasing from downhole, to flowline to surface facility and heater treaters.

Table 2 shows the average, minimum and maximum component of the brines modeled in Figure 2. Brine 1a was selected to represent an unrealistic, worst-case, highest m-alkalinity scenario where the m-alkalinity was 3,904 mg/L (Table 2). For DSL testing, m-alkalinity and organic acids were checked and slightly adjusted for brine 1b. Organic acids were not subtracted from m-alkalinity for testing with Brine 1a. Organic acids have been measured from 552 – 681 mg/l in this system. Therefore, it is highly unlikely the true bicarbonate concentration is 3,904 mg/L, however Brine 1a was still selected for performance testing to better understand a worst-case MED. Brine 2 was selected for testing because it had the highest scaling indices (SI) for calcite and the highest number of pounds per thousand barrels (PTB) precipitated for the most recent waters collected in the system. Further, the m-alkalinity minus organic acids was similar to the average and mixed fluid compositions with slightly higher calcium content. Therefore, it was believed Brine 2 should yield a more realistic average MED assuming mixing is occurring at the facility.

Table 2 – (Left) mixing compositions of waters that could occur in the system. (Right) Brine 1a, 1b, 2 selected performance testing. Grey fields indicate variables included in the synthetic brines.

	Modeled Water Mixes		Performance Testing		
Brine Components	Surface Facility Mix # 1	Surface Facility Mix # 2	Brine 1a Static Bottle	Brine 1b DSL	Brine 2 Static Bottle & DSL
Na^+	69,864	60,203	69,870	70,253	65,700
K^+	985	943	936	936	969
Mg^{2+}	726	617	498	498	1,010
Ca^{2+}	3,896	3,409	2,621	2,621	5,490
Sr^{2+}	185	208	144	144	243
Ba^{2+}	0.36	0.43	0.00	0.00	0.40
Fe^{2+}	33	43	0	0 - 50	0-100
SO^{4-}	3,174	2,551	3,600	3,600	2,562
Cl^-	109,224	98,553	109,770	109,770	117,649
M Alkalinity	2,318	2,089	3,904	3,329	2,050
M Alkalinity minus organic acids	1,670	1,469	3,279	2,764	1,723
Organic Acids (Acetate equivalent)	648	620	625	565	567
In-situ Modeled Heater Treater pH	6.51	6.52	6.68	6.25	6.25

Notice that the modeled in-situ pH of the heater treater conditions for the mixed brine compositions is 6.51-6.52 (Table 2). In Table 3 we evaluated the in-situ pH from SSP 2019 modeling nodes to better understand what the most representative surface pH would be to determine pH adjustments for performance testing. Table 3 shows the increasing risk of carbonate scale from SSP modeling at surface, correlating with dropping pressure and increasing modeled in-situ pH. A pH of ~6.5 was selected to be used in performance testing based on these results to represent a worst-case scenario as it is the median pH of the water tanks, yet slightly greater than the average in-situ pH across the system and SSP2019 modeling risk (Figure 2) increases at surface conditions.

Table 3 – Evaluation of in-situ pH using SSP 2019 modeling from downhole to facility conditions. Statistical metrics incorporate 128 modeling scenarios and 32 individual water analysis. A representative surface pH of ~6.5 was selected for brine adjustment in performance testing.

In-Situ pH Modeling						
SSP modeling scenario	(°F)		(psia)	Stats	Modeled In-Situ pH	
Estimated Water tank Temp. & Pressure	75	downstream ↑	20	Average	6.29	↑ Decreasing Pressure & Increasing pH
				Min	4.00	
				Max	6.85	
				Median	6.50	
Estimated Maximum heater Treater Temp. & Pressure	150		60	Average	6.11	
				Min	4.00	
				Max	6.68	
				Median	6.30	
Estimated Maximum Flowline Temp. & Pressure	85		300	Average	5.25	
				Min	3.87	
				Max	5.74	
				Median	5.38	
Estimated Downhole Temp. & Pressure	160	upstream	1000	Average	5.08	
				Min	3.80	
				Max	5.56	
				Median	5.20	

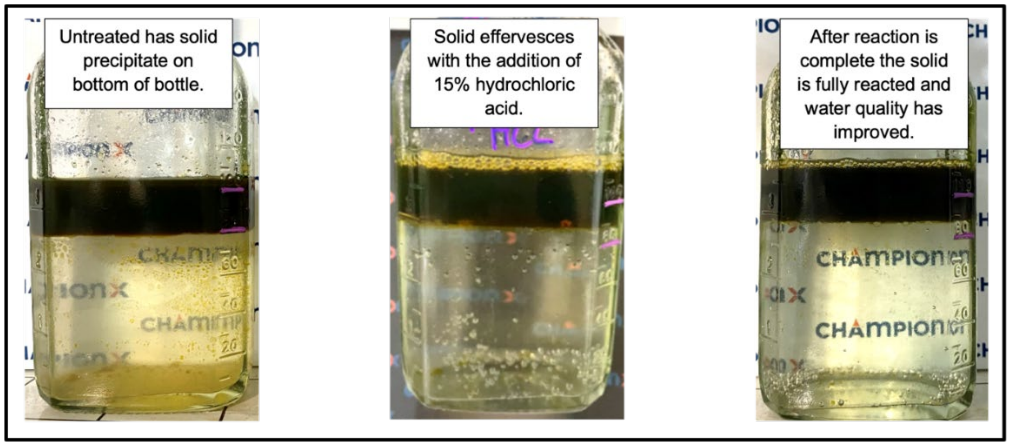
Produced Fluid Compatibility

Fresh produced fluid was collected from well brine 2 was collected from listed in Table 4. 80% water and 20% oil was used to simulate production. While inclusion of iron in testing and oxidation of fluid can impact results (Cushner et al., 1989; Dyer et al., 2000; Graham et al., 2003; Kriel et al., 1994; Lu et al., 2016; Guan et al., 2008; Kan et al., 2008; Marlow et al., 2009; Shen et al., 2011; Zhang et al., 2015; Zhang et al., 2016; Haiping et al. 2016; Spicka et al., 2020), this was viewed as the ideal way to select the most compatible scale inhibitor as product incompatibility was suspected in current sub-optimal treatments. Four phosphonate and one polymer-based products did not have evidence of solids and passed at all conditions. Figure 3 summarizes that the solids that formed in the blank were solubilized with hydrochloric acid. Photos in Figure 4 demonstrate select results in Table 4 and how the results in Table 4 were determined. Figure 5 shows zoomed in images of product 7 which had the best appearance in the bottles at both 1,000ppm and 10,000ppm.

Table 4 – Summary of observations made during produce fluid compatibility. Four phosphonates and 1 polymer are able to pass at all conditions.

Scale Inhibitor Type	Product	ppm	Ambient ~80-86^{o}F	Low Temp Heater treater/worst case flowline 120^{o}F for 2 hours	Heater Treater Temperatures/Estimated Downhole Temperatures 160^{o}F for 2 hours
Untreated	Untreated	0	Pass - no solids	Pass - no solids	Solid scale formed - effervesced with HCl addition and all solids dissolved
Ph.	1	1,000	Fail - white solids	Fail - white solids	Fail - white solids
Ph.	1	10,000	Fail - white solids	Fail - white solids	Fail - white solids
Ph.	2	1,000	Pass - no solids	Fail - white solids	Fail - white solids
Ph.	2	10,000	Fail - white solids	Fail - white solids	Fail - white solids
Ph.	3	1,000	Fail - white solids	Fail - white solids	Fail - white solids
Ply.	4	1,000	Pass - no solids	Pass - no solids	Pass - no solids
Ph.	5	1,000	Pass - no solids	Pass - no solids	Pass - no solids
Ph.	6	1,000	Pass - no solids	Pass - no solids	Pass - no solids
Ph.	7	1,000	Pass - no solids	Pass - no solids	Pass - no solids best water quality
Ph.	7	10,000	Pass - no solids	Pass - no solids	Pass - no solids best water quality
Ph.	8	1,000	Pass - no solids	Pass - no solids	Pass - no solids best water quality
Ph.	8	10,000	Pass - no solids	Pass - no solids	Pass - no solids best water quality
Ph.	9	1,000	Fail - white solids	Fail - white solids	Fail - white solids
Ply.	10	1,000	Pass - no solids	Fail - white solids	Fail - white solids
PE.	11	1,000	Pass - no solids	Fail - white solids	Fail - white solids

Some tables and charts abbreviate phosphonate (Ph.), Phosphate Ester (PE.) and Polymer (Ply.)


Untreated has solid precipitate on bottom of bottle.

Solid effervesces with the addition of 15% hydrochloric acid.

After reaction is complete the solid is fully reacted and water quality has improved.

Figure 3 – (Left) Untreated sample at the end of produced fluid testing. (Middle) Untreated sample at the end of testing plus the addition of 1 ml of 15% hydrochloric (HCl) acid, showing effervescence indicating the formation of carbonate scale during the test. (Right) Untreated bottle after rection with HCl ceases showing clear water with no signs of remaining solids.

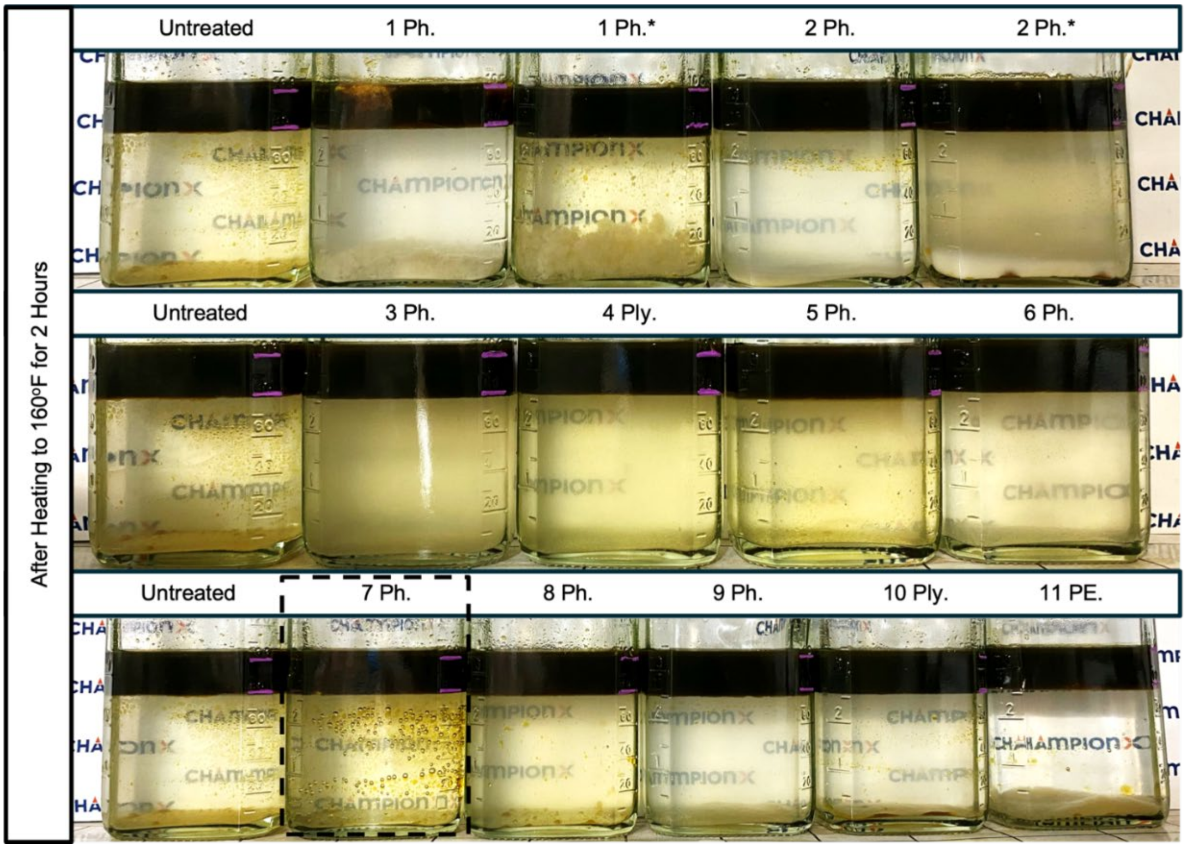


Figure 4 - Example of bottle photos of the produced fluid compatibility experiment at 160oF. Note the solids at the base of many of the bottles and the water quality compared to the untreated bottle on the far left. Phosphonate 7 and 8 at 1,000ppm have the best appearance when compared to the blank (All bottles were dosed with 1,000 ppm unless a *is noted which means it was dosed at 10,000 ppm).

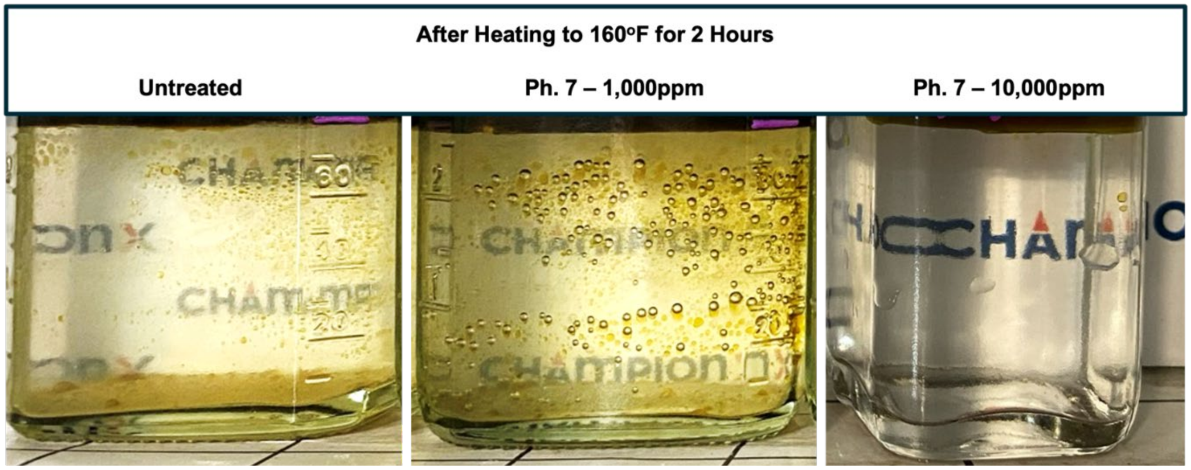


Figure 5 – (Left) Untreated sample at the end of produced fluid testing close up image showing solids in the bottom of the bottle. (Middle) Phosphonate 7 at 1,000ppm. (Right) Phosphonate 7 at 10,000ppm. Both 1,000ppm and 10,000ppm look better than the untreated bottle.

Static Bottle Results

NACE Standard TM0374-2015 style static/synthetic brine experiments were used to identify the MED of scale inhibitor chemistries at ambient, low temperature heater and high temperature heater treater conditions (Table 5). This test further allowed us to understand scale inhibitor compatibility in synthetic fluids without the presence of iron.

While DSL can be the preferred method for evaluating scale inhibitors in carbonate scaling environments, static tests were used with the thought that standard pressure and loss of CO_2 through the bottle caps will likely occur. This would help to create a situation to understand how loss of CO_2 and the resulting pH increase impacts the MED. The SSP 2019 modeling (Figure 2) showed an increase in risk with decreasing pressure and increasing pH. Top performer phosphonate #7, plus a few select chemistries which had shown performance in offset systems, were carried into DSL testing.

Table 5 – 8 MED of scale inhibitors in brines 1a & 2 without iron. Brine 1a had the highest alkalinity measured in all historical and new waters. Brine 2 is more representative of mixing and average water compositions with the highest SI of the most recent set of waters collected from the system. Phosphonate #7 has the lowest MED compared to all other scale inhibitors. Even in the absence of iron phosphonate #3 and phosphate ester #11 showed evidence of incompatibility in testing with synthetic brine #2.

Static Bottle (no iron present)			
Brine	Scale Inhibitor Type	Product	MED
Ambient ~84^{o}F & 14.7psi			
Brine1a	Phosphonate	5	100-250
Brine1a	Phosphonate	6	100-250
Brine1a	Phosphonate	8	100-250
Brine1a	Phosphonate	7	25-50
Brine 2	Ph. Ply. PhE.	3,5,6,7,8,10,11	NA Blank did not scale
Estimated Worst Case Surface Facility Conditions (~100^{o}F & 14.7psi) MED in ppm			
Brine1a	Phosphonate	5	100-250
Brine1a	Phosphonate	6	250-500
Brine1a	Phosphonate	8	100-250
Brine1a	Phosphonate	7	75-100
Brine 2	Ph. Ply. PhE.	3,5,6,7,8,10,11	<25ppm
Severe Heater Treater Surface Conditions & Worst Case Downhole Thermal Conditions (~160^{o}F & 14.7psi) MED in ppm			
Brine 2	Phosphonate	3	Incompatible
Brine 2	Phosphonate	5	>100 - <250ppm
Brine 2	Phosphonate	6	>100 - <250ppm
Brine 2	Phosphonate	7	>25ppm - <50ppm
Brine 2	Phosphonate	8	> 75ppm - <100ppm
Brine 2	Polymer	10	>50 - <75ppm
Brine 2	Phosphate Ester	11	Incompatible

DSL Results

Given the performance of phosphonate #7 in the previous testing, it was carried into DSL testing with both brines. Two other phosphonates were selected based on performance on other wells in the area. Alkalinity of brine 1a was reconfirmed in the field and slightly modified for DSL testing with brine 1b conditions plus organic acids (Table 2). 50 mg/L and 100 mg/L iron was used to represent best-case and average-case scenarios. An elevated pressure of 600psi was selected in the hopes that the resulting MED could in the future be used downhole or as far upstream as possible and carry through the system. Again phosphate #7 was the top performer.

Table 6 – DSL results with and without iron. Phosphonate 7 is the top performer with the lowest MED with and without iron.

Scale Inhibitor Class	Product	Iron (mg/l)	MED (ppm)
Brine 1b			
Phosphonate	1	0	2
Phosphonate	2	0	1
Phosphonate	7	0	2
Phosphonate	1	50	>100ppm
Phosphonate	2	50	>100ppm
Phosphonate	7	50	>80 to 100ppm
Brine 2			
Phosphonate	7	0	>40ppm to 50ppm
Phosphonate	7	100	>100ppm to 150ppm

Field Results

Based on these results 50 ppm of phosphonate 7 was trialed in the field. While the MED with iron identified in testing was greater than 50 ppm the product appeared to handle the iron well in the produced fluid compatibility tests. The product was applied as far upstream as possible prior to any mixing at the facility. Regular phosphate (PO_4) residuals were collected to make sure the product was carried through the system.

After 26 months of treatment with phosphonate 7 at 50ppm the operator reported:

1. Zero flowline and facility scale-offs since program implementation (as of abstract submission date = 26-month duration).
2. Allows for the use of heater treaters in winter to sell oil, without scaling off the heaters.
3. Provides operational efficiency gains through: a) decommission of small satellite facilities previously used to isolate high scale risk brines. Mixing of treated high-risk waters can now be comingled at the larger central tank battery. b) less manpower needed for routine cleanouts.

Efforts were made to optimize treatment rate down from 50 ppm to see if economics of treating could be improved. Within approximately 1 week the operator reported evidence of scale precipitation based on differential pressure changes. As a result, treatment rates were increased back to 50 ppm. As of the date of this publication treatment rates remain at 50 ppm.

CONCLUSIONS

1. Based on field application phosphonate 7 provides an infield MED of 50 ppm.
2. An in-field MED of 50 ppm aligned better with performance testing without iron in pH adjusted static bottle tests and DSL testing without iron for Brine 2 (Table 7).

Table 7 – Summary of bench testing results for phosphonate 7.

Test	Product	Iron (mg/l)	MED (ppm)
		Brine 1	
Static Bottle - ~84°F	Ph. 7	0	25-50
Static Bottle - 100°F	Ph. 7	0	75-100
DSL - 160°F 600psi	Ph. 7	0	2
DSL - 160°F 600psi	Ph. 7	50	>80 to 100ppm
		Brine 2	
Static Bottle - ~84°F	Ph. 7	0	NA Blank did not scale
Static Bottle - 100°F	Ph. 7	0	<25ppm
Static Bottle - 160°F	Ph. 7	0	>25ppm - <50ppm
DSL - 160°F 600psi	Ph. 7	0	>40ppm to 50ppm
DSL - 160°F 600psi	Ph. 7	100	>100ppm to 150ppm

3. Both Brines 1 and 2 were able to yield the infield MED of ~50ppm in bench top testing under various scenarios.
4. Produced fluid compatibility in the presence of iron was considered a critical step in identifying the right chemistry compatible with the fluids and system temperatures.
5. Proper pH adjustment appears to play a critical role in proper bench identification of MED in high alkalinity systems. As found in previous work (Graham, G. M., Collins, I. R., Stalker, R., and I. J. Littlehales., 2022)
6. SSP 2019 modeling indicated scaling risk increased with decreasing pressure and increasing pH, supporting the belief that loss of CO2 and resulting pH increase are driving factors of carbonate precipitation in this system.
7. Produced brine alkalinity heterogeneity observed in Avalon waters ~10-40 miles from each other aligns with heterogeneity in the geology reservoir rocks in the published in the literature.
8. Heterogeneity of Avalon waters may make proactive chemical treatments challenging to design as future Avalon assets are drilled and completed. Attention should be placed on new Avalon wells and scale risk should be assessed over the entire life of the asset.

9. Heterogeneity of waters and mole% CO_2 of the Avalon formation has the potential to impact future midstream SWD and gas pipeline flow assurance and asset integrity risk of operations if more Avalon wells are drilled.

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