DELAWARE BASIN FORMATIONAL SOLID DEPOSIT TRENDS, A DATA DRIVEN LOOK AT DEVELOPING PROACTIVE CHEMICAL TREATMENT STRATEGIES

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ABSTRACT

The Permian Basin is well known for multiple remunerative producing zones. Recent development from the Delaware Basin has presented a need for economical chemical selections. Chemical treatment strategies applied in contemporaneous formations in the Midland Basin may not result in an optimized solids risk mitigation approach for the New Mexico Delaware Basin. Having the right treatment strategy in place is essential in preventing failures and downtime due to under deposit corrosion, microbiologically influenced corrosion (MIC), plugging and emulsion issues. Most operators have a firm understanding of localized problem facilities and well sets but have a less defined macroscopic perspective needed to minimize risk in terms of geography, geology and water chemistry. This paper highlights a tailored chemical treatment strategy developed for solid mitigation for a Delaware Basin operator. Over 200 New Mexico and Texas State line Delaware Basin solid samples were collected over a two-year period, spanning 7 distinct producing intervals. Focus was placed on the most common producing zones such as the Wolfcamp, Bone Springs and Avalon formations. A statistical approach was taken to break down which formations have the greatest potential for paraffin, carbonate, acid soluble iron compounds and sulfate scales. Trends in the data suggested certain formations are more prone to certain types of solid precipitation. The data is in line with field observations across the Northern half of the Delaware Basin. Tying solid deposition history on a formational level helped the customer understand where treatment was no longer needed, where it was still required and where it may be needed in the future. The trends provide a proactive road map for risk mitigation and treatment optimization before a solid deposition event has occurred. An understanding of these trends have potential to save operators downtime and additional financial burdens associated with work over costs and deferred production in the Northern half of the Delaware Basin. A similar macroscopic approach in other basins may be applied to identify what proactive treatment strategies could be developed based upon the unique challenges of those regions and similarly improve field performance.

INTRODUCTION

Precipitation of solids such as scale, paraffin and iron sulfide in equipment can result in costly downtime. Issues related to solids can be prevented or mitigated through successful chemical and/or mechanical treatment strategies. There is a need for optimized cost-effective solids mitigation and treatment strategies for oil and gas operators across multiple basins. The key is knowing what type of solids have the greatest potential to form before they precipitate and cause issues within a given system. There is a long-standing history of successful chemical and mechanical treatment strategies for solids in the Midland Basin, less is known about recent unconventional developments in the Delaware Basin, particularly in the Wolfcamp and Bone Springs formations. A macroscopic, data driven view of the types of solids that have the greatest potential to form from Delaware Basin producing intervals, would allow operators to create a tailor fit chemical and mechanical treatment strategy based off formation.

The Delaware Basin, located within the Permian Basin, is a series of stacked plays. The Avalon sits above the 1st, 2nd and 3rd Bone Springs all of which are Leonard age strata shown in Figure 1a. These formations sit stratigraphically above the Wolfcamp formations. Each producing interval has similar and unique characteristics, these difference result in differences in the produced water and oil properties in Table 1, for the geographic area of interest shown in Figure 1b. These fluid properties will directly affect risk of solid precipitation. Over the last decade, the most common unconventional targets in the Delaware Basin have been the Avalon, Bone Springs and Wolfcamp formations which are the focus of this paper.

Figure 1

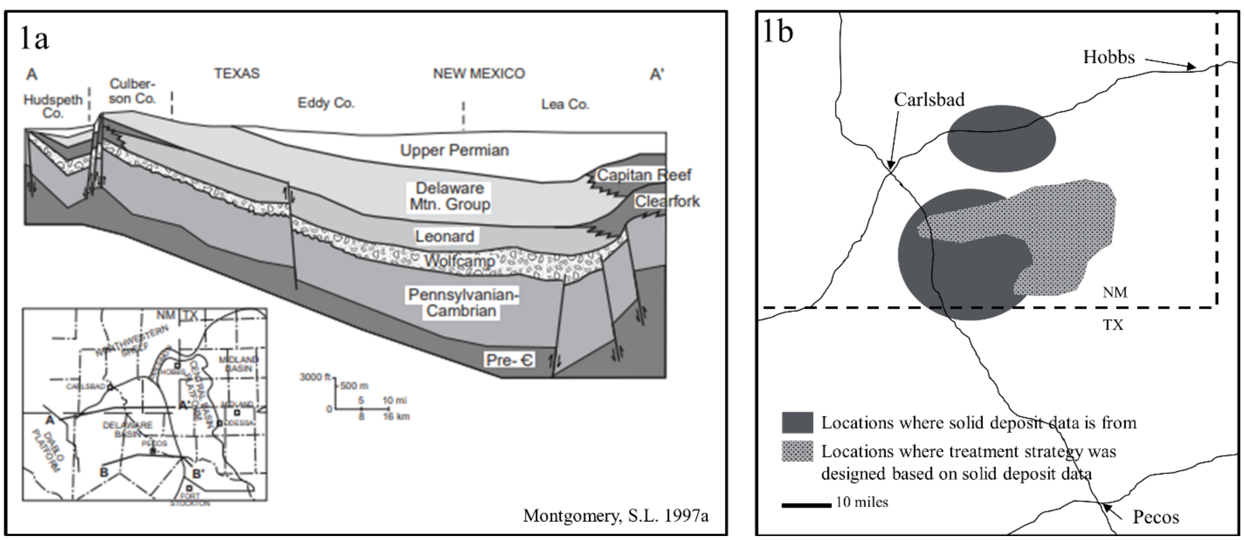

Figure 1a - Cross section of the New Mexico Delaware Basin near the area of interest. Figure 1b - Map of the Delaware Basin. Dark grey ovals show geographic distribution of locations where solid deposit data is from. Grey textured field shows locations of wells currently using the formation-based treatment strategy outlined here.

Table 1

Water Data							
Formation	Avalon Shale	1st Bone Spring	2nd Bone Spring	3rd Bone Spring	Wolfcamp A	Wolfcamp C	Wolfcamp D
# of Water Analysis	17	5	225	22	83	9	81
Sodium	53,100 - 82,300	59,600 - 68,800	15,244 - 101,000	20,200 - 62,300	20,400 - 57,300	32,700 - 38,800	21,800 - 65,400
Potassium	878 - 1,360	1,050 - 2,760	296 - 3,673	398 - 1,924	16 - 2,217	533 - 697	291 - 2,167
Magnesium	475 - 2,520	568 - 2,960	95 - 2,980	55 - 2,200	84 - 1,170	1 - 501	0 - 1,850
Calcium	1,210 - 9,290	2,990 - 18,800	1,920 - 13,300	1,510 - 9,260	1,210 - 7,060	2,250 - 3,740	1,874 - 7,490
Strontium	410 - 1,480	542 - 1240	128 - 2,320	400 - 1,440	11 - 1,670	810 - 1,180	490 - 1,820
Barium	0 - 20	0 - 17	0 - 155	2 - 35	0 - 76	4 - 11	1 - 58
Iron	0 - 214	10 - 100	0 - 547	3 - 116	0 - 177	5 - 192	0 - 385
Manganese	0 - 4	0 - 6	0 - 6	1 - 3	0 - 4	1 - 2	0 - 12
Chloride	93,087 - 159,090	78,335 - 100,724	29,828 - 178,958	39,380 - 112,208	42,930 - 82,953	41,148 - 72,102	28,077 - 109,415
Sulfate	111 - 2,453	259 - 1,069	0 - 1,117	11 - 600	5.9 - 1,747	109 - 534	3 - 743
Titrated M Alkalinity	37 - 1,220	390 - 2,159	12 - 915	24 - 610	37 - 1,025	49 - 390	24 - 756
TDS	165,818 - 240,615	154,696 - 177,276	49,260 - 248,973	62,967 - 180,558	68,591 - 142,256	79,541 - 112,121	63,343 - 182,339
Dissolved CO2	100 - 800	270 - 700	5 - 3,600	90 - 549	49 - 740	40 - 620	5 - 900
Dissolved H2S	0 - 17	0 - 26	0 - 51	0 - 17	0 - 17	0 - 17	0 - 68
Measured pH	5.0 - 7.6	5.0 – 7.0	5.0 – 8.0	6.0 - 7.5	5.7 - 7.7	6.5 - 7.5	6.0 - 7.8
Oil Data*							
# of Oil Analysis	12	3	48	2	33	7	7
Average of API °	43.5	41.8	42.7	45.7	45.8	51.2	52.6
API °	41.0- 44.7	38.5-46.3	36.3 – 47.7	43.4 – 48.0	29.6-53.5	46.4 – 54.4	49.3 – 54.7
Average of WAT (°F)	107	78	95	73	93	103	80
WAT (°F)	82 - 142	64 - 85	49 - 149	40 - 108	43 - 117	76 - 120	37 - 103
Average % Wax	4.8	4.9	4.2	3.3	3.7	2.7	1.9
% Wax	3.3 – 9.9	3.9 – 5.4	2.4 – 6.7	2.9 - 3.7	1.1 – 5.0	1.8 – 4.3	1.3 – 2.5

Table 1 - Table of water analysis and oil data from locations where solid data was collected. All water analysis cations, anions and dissolved gases are reported in mg/l. **Due to smaller oil data dataset from locations where solids were collected oil analysis from wells currently being treated in Figure 1b were also included.*

Typical proactive solids risk mitigation tools include the use of monitoring data incorporated with “rule of thumb” risk tables, key performance indicators and/or modeling. While useful, these exercises are always limited by modeling assumptions and the analytical data collected at surface sample points. Modeling and “rule of thumb tables" are useful and have their place but of course are only as good as the inputs available. For example, if scale forms up stream of the sample collection point the modeled scale risk may be low because the components needed to form the scale are no longer present in the water analysis. Another example is the concept that paraffin has a high potential to form if the system cools below the wax appearance temperature (WAT) but issues may not be seen if the paraffin only precipitates out in small quantities and/or never has a chance to floc together and agglomerate on equipment. Other variables such as oil composition, API gravity, percent wax, water oil ratio, shear, flow regime and gas breakout among others can effect paraffin precipitation. Monger-McClure (1997) concluded that both thermodynamic and deposition rate centric paraffin predictive models showed very poor correlations with paraffin deposition in the field.

Designing cost effective proactive chemical or mechanical treatment strategies and optimizing those efforts is a challenging dynamic process. Common questions include where do I need and not need chemical treatment? If I need chemical treatment, what type do I need? Scale inhibitor? Iron chelators? Paraffin inhibitors/dispersants? Historically, operators typically take one of two approaches, treat everything and changing chemical type on an as needed basis or only treat locations where a known problem has occurred in the past. If we decide to treat everywhere which type of treatment should go where? Where can I be less aggressive to save on treatment costs? Where do I need to be more aggressive to minimize the risk of facility shut in? These types of questions can be very challenging to answer especially across large assets. Answering them in the best way possible is essential to minimizing costly downtime. The data and risk assessment strategy presented here by no means can answer all of these questions but is a step in the right direction.

Theory and/or Methods

From conversations across the Delaware Basin, it is clear some people have experience with some formations having more "scale" or "paraffin" issues but this has all been based on individual field experience in localized areas. For example, it is not uncommon to hear that the 2nd Bone Springs tends to have paraffin issues. If this is true on a larger scale than widespread untreated solid deposit data should be able to tell us which solids are the most probable, from each formation. If a pattern can be found in the data than a proactive risk mitigation treatment strategy could potentially be defined by formation. If such a data trend exists, it would have the potential to provide great value and simplify upfront treatment selection/methodology. Then, optimization of these programs over time would provide aditional cost saving benefits.

206 solid samples, collected over a two-year span, were collected from wells and surface facilities spanning 7 distinct producing intervals located in the Northern Delaware Basin (Figure 1b). Efforts were made to present solids from mostly untreated systems, in theory this will allow for the natural potential of solid type per formation to be identified if a trend exists. Solid deposit breakdown was performed using a standard method using a series of solvent and acid washes with before and after weights to

identify solid types. Solids are broken into a series of groups using this method and then sorted by producing formation interval (Table 2).

- “Paraffin” = hydrocarbon content from xylene and hexane washes are labeled “paraffin” **Asphaltene precipitation in this area is rare during primary production.*
- “Carbonate” = acetic acid soluble material.
- “Acid Soluble Iron Compounds” = hydrochloric soluble material, usually consists of acid soluble forms of Fe_xS_x and Fe_xO_x.
- “Acid Insoluble Material” = remaining material after washes, usually consists of Si_xO_x and sulfate scales.

Results

Results are highlighted in detail in Table 2 and Figures 3 & 4. Trends in the data suggested certain formations are more prone to certain types of solid precipitation. The solid deposit data correlates well with field observations and associated water and oil chemistry (Table 1) across the Northern half of the Delaware Basin. The bullet points below highlight the results and show which solids have the greatest potential (left) and lowest potential (right) to form in systems of the associated formational fluids.

- Avalon = Carbonate > Paraffin > Acid Soluble Iron Compounds
- 1st Bone Springs = Paraffin > Carbonate > Acid Soluble Iron Compounds
- 2nd Bone Springs = Paraffin > Carbonate > Acid Soluble Iron Compounds
- 3rd Bone Springs = Carbonate >Paraffin > Acid Soluble Iron Compounds
- Wolfcamp A = Acid Soluble Iron Compounds > Paraffin > Carbonate
- Wolfcamp C, D = Acid Soluble Iron Compounds > Carbonate > Paraffin

11 samples collected from Avalon fluids, show that carbonate scale has the greatest potential to form followed by paraffin than acid soluble iron compounds (Table 2, Figures 3 & 4). The water chemistry (Table 1) is in line with the potential for elevated M-alkalinity (“titrated bicarbonate”) and available calcium of the fluids, compared to the 2nd Bone Springs and Wolfcamp waters. Lower average API and higher average % wax compared to the Wolfcamp C and D oils are consistent with increased paraffin deposition potential (Table 2, Figures 3 & 4). Avalon oil here is more like the Bone Springs than Wolfcamp (Table 1).

115 Bone Springs samples show that paraffin has the greatest potential to form (Table 2, Figures 3 & 4). The 1^{st} and 2^{nd} Bone Spring are more likely to have greater paraffin content in solid deposits (Table 2, Figures 3 & 4). The 3^{rd} Bone Spring is only slightly more likely to have a carbonate potential over paraffin (Table 2, Figures 3 & 4). This is an interesting, unexpected outcome because the water chemistry, the M-alkalinity and calcium of the 1^{st} Bone Springs is significantly higher than that of the 3^{rd} Bone Springs. Lower average API and higher average % wax compared to the Wolfcamp C and D oils (Table 1) is consistent with the increased paraffin risk.

80 Wolfcamp samples show that acid soluble iron compounds have the greatest potential to form (Table 2, Figures 3 & 4). Acid soluble iron compounds here refers to solids such as iron sulfide or iron oxide that is soluble in hydrochloric acid. This is very interesting given the low H_2S content of Wolfcamp brines (Table 1). Wolfcamp A has a slightly elevated potential for paraffin over Wolfcamp C and D based on solids data. These differences in Wolfcamp zones are consistent with the Wolfcamp A oil characteristics having more similarities to the Bone Springs oils where the Wolfcamp C and D having higher average API and lower % wax (Table 1). Higher API should give the crude more natural solvency (Ferworn, K. et al. 1997; Noll, L. 1992) and lower % wax decreases available volume of paraffin capable of precipitating. Further, lower potential for carbonate makes sense with the lower M-alkalinity and calcium of these waters compared to that of the Avalon and Bone Springs.

Table 2

Type of Solid		**Hydrocarbon**			**Iron - Acid Soluble**		
Formation	Total # of solid samples	>50%	50%-10%	<10%	>50%	50%-10%	<10%
AVALON SHALE	11	2	4	5	1	5	5
1ST BONE SPRING	8	5	1	2	1	4	3
2ND BONE SPRING	70	25	24	21	4	26	40
3RD BONE SPRING	37	9	10	18	5	15	17
WOLFCAMP A	36	12	6	18	11	18	7
WOLFCAMP C	5	0	1	4	4	1	0
WOLFCAMP D	39	3	9	27	24	12	3
Total # of Analysis	**206**	**56**	**55**	**95**	**50**	**81**	**75**
Type of Solid		**Carbonate**			**Acid Insoluble**		
Formation	Total # of solid samples	>50%	50%-10%	<10%	>50%	50%-10%	<10%
AVALON SHALE	11	3	5	3	1	1	9
1ST BONE SPRING	8	1	2	5	0	0	8
2ND BONE SPRING	70	20	20	30	3	8	58
3RD BONE SPRING	37	11	16	10	2	6	28
WOLFCAMP A	36	5	18	13	3	3	30
WOLFCAMP C	5	0	3	2	0	1	4

Type of Solid		Hydrocarbon			Iron - Acid Soluble		
Formation	Total # of solid samples	>50%	50%-10%	<10%	>50%	50%-10%	<10%
WOLFCAMP D	39	2	23	14	3	6	30
Total # of Analysis	**206**	**42**	**87**	**77**	**12**	**25**	**167**

Table 2 - Table detail of all results

The solid deposit data above allowed for the design of a formation-based treatment strategy (Figure 2). This treatment strategy has been in practice downhole on gas lifted wells and/or at surface for about one calendar year on approximately 100 wells/locations located in the Northern half of the Delaware basin (Figure 1b). Results are promising since zero chemical related failures have occurred downhole and at surface since implementation of this strategy at these locations.

The solid deposit data above facilitated design of a formation specific treatment strategy (Figure 2). Custom programs 1, 2 and 3 consider solid risk potential of each formation as well as other factors including asset integrity, phase separation and/or microbiological related concerns. Custom programs 1, 2 and 3 have been in practice downhole on gas lifted wells and/or at surface for about one calendar year on approximately 100 wells/locations located in the Northern half of the Delaware basin (Figure 1b). Results are promising since zero chemical related failures have occurred downhole and at surface since the publication of this article and implementation of this strategy at these locations.

Table 3

Formation	# of Wells Treated using treatment strategy in Figure 2
Lower Brushy Canyon	1
Avalon	5
1st Bone Springs	2
2nd Bone Springs	38
3rd Bone Springs	9
Wolfcamp A	10
Wolfcamp B	5
Wolfcamp C	11
Wolfcamp XY	27
Total	**108**

Table 3 - Formational break down of wells currently being treated with the treatment strategy outlined in Figure 2. Geographic proximity to locations where solid deposit data is from is shown in Figure 1b.

Figure 2

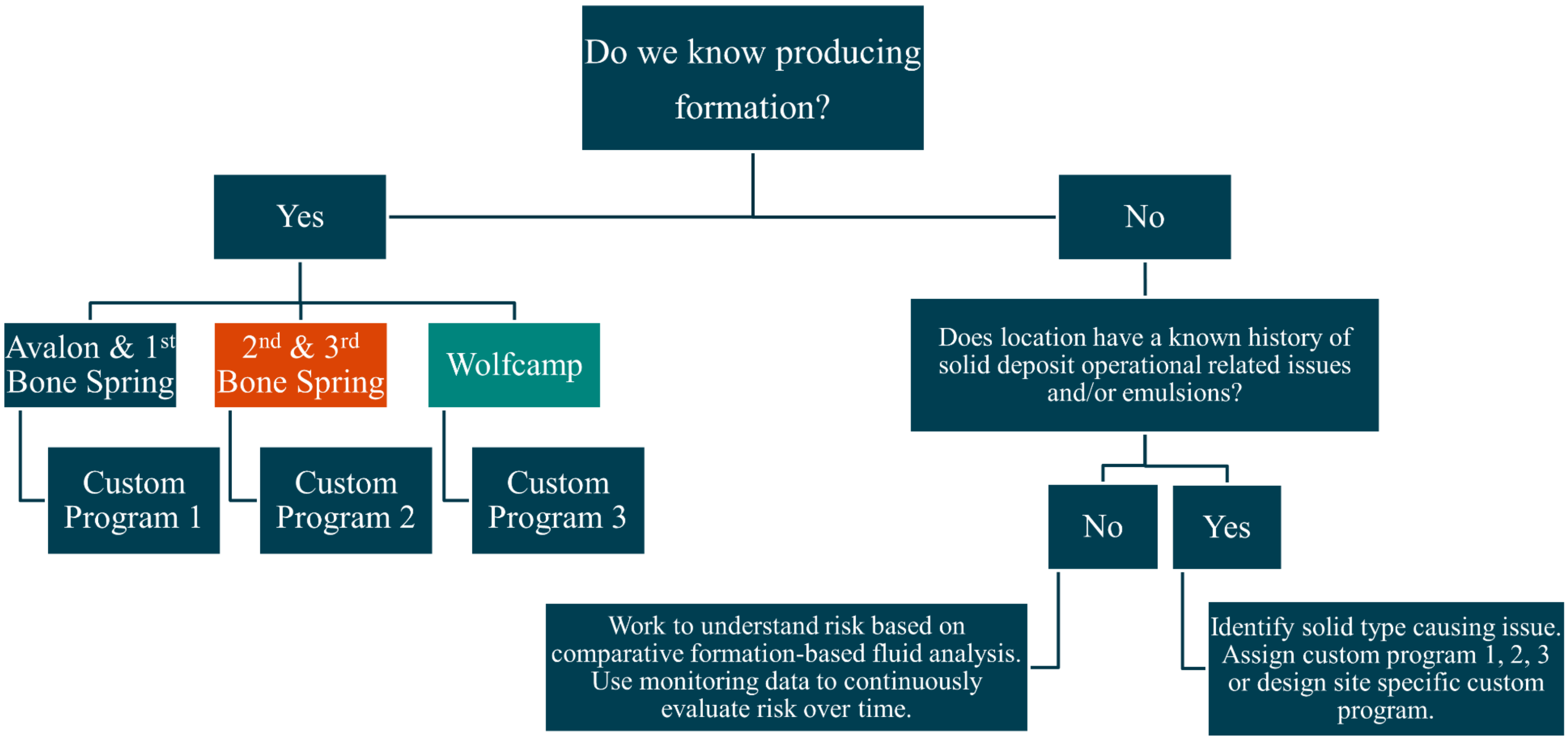

Figure 3 - Treatment strategy design based on formational solid deposit data.

Figure 3

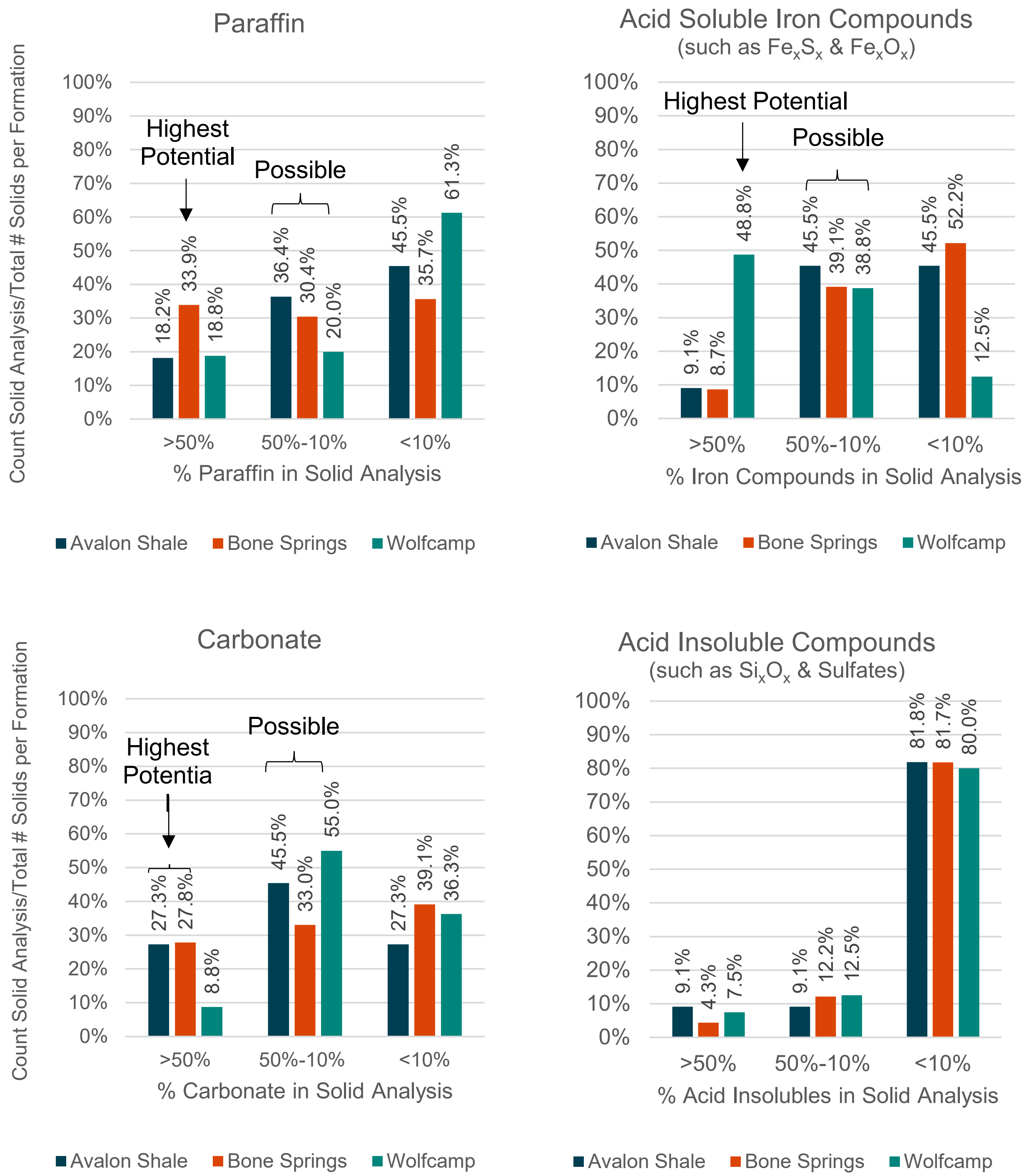

Figure 4 - Solid deposit results summarized by major producing formation group.

Figure 4

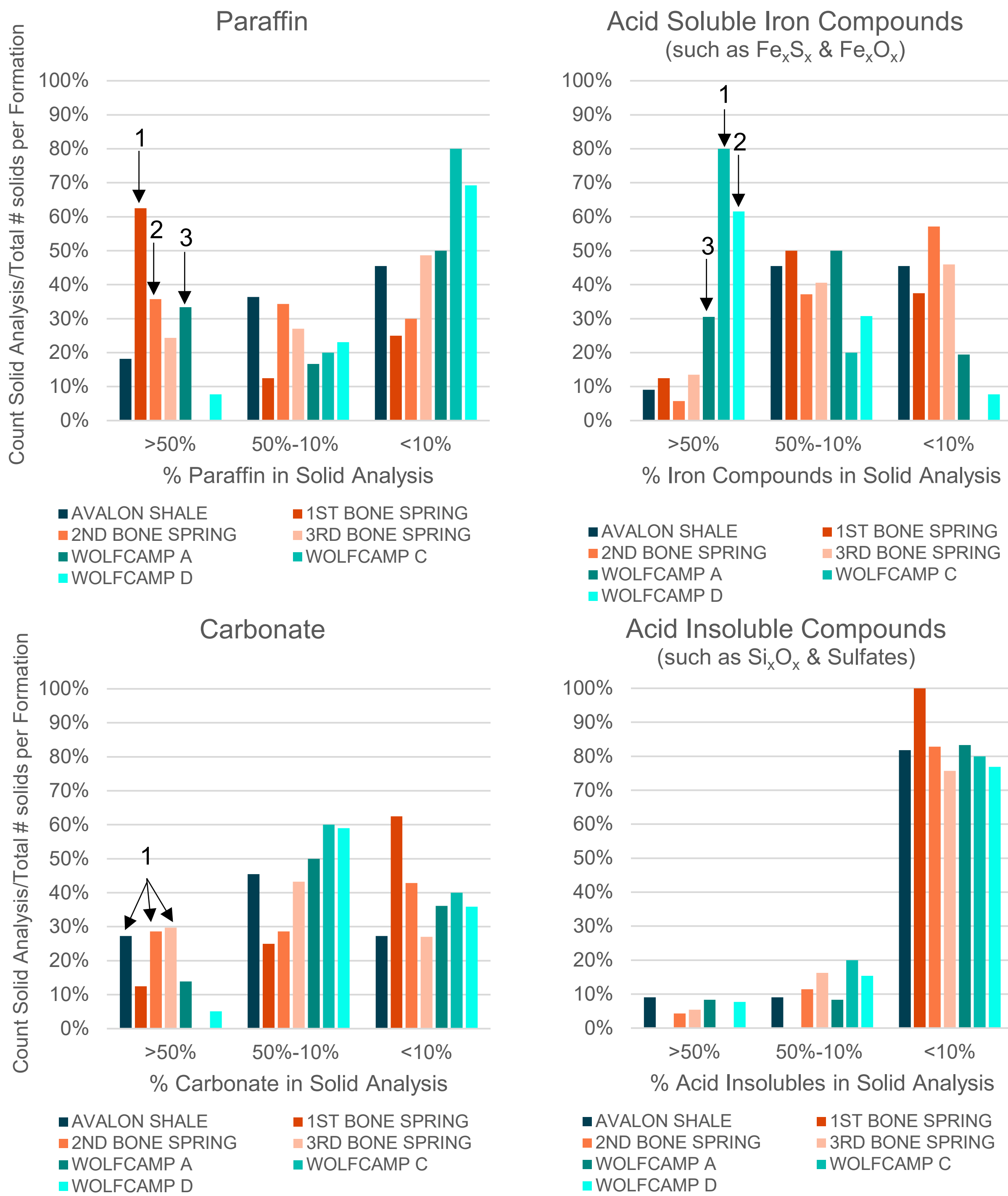

Figure 5 - Detailed solid deposit results by specific producing interval.

Discussion

Data trending of solids analyses from Delaware Basin wells with no chemical applications suggests that there is a tendency for the Avalon formation to have the greatest carbonate potential, the Bone Springs formations to have the greatest paraffin potential and the Wolfcamp formation to have the greatest acid soluble iron compound potential. The solid deposit data above helped design a formation-based treatment strategy for solid mitigation which is currently showing promise on approximately 100 wells, with zero chemical related failures over an almost one-year treatment period. It should be noted that data shows that paraffin, carbonate and acid soluble iron compounds all have the potential to form, in lesser quantities in all formations.

Given the elevated titrated M-Alkalinity and available calcium levels in the Avalon and some 1st Bone Spring brines, care should be taken to minimize carbonate scale risk in these formations. Previous dynamic scale loop testing work using different scale inhibitor types with variable iron content, shows that the Bone Springs brines do have the potential to form carbonate scale in the lab, this is in line with the solid data from the field. Carbonate scale was also present in many of the 2nd and 3rd Bone Spring solid deposits. Therefore, a well-by-well treatment strategy may be needed on Bone Springs wells where treatment for corrosion, paraffin +/- carbonate scale may be required. Looking at the Wax Appearance Temperatures (WAT) and M-Alkalinity on a local level for wells producing from the 1st, 2nd and 3rd Bone springs, will be essential to optimizing chemical or mechanical treatment in this formation. If treatment for carbonate scale is required, minimizing available iron in the system will be important for product selection and optimizing carbonate scale treatments.

The trend for the 1st and 2nd Bone Springs to show the greatest paraffin precipitation potential is in line with field observations and oil data when compared to the lower risk Wolfcamp C and D (Table 1). Understanding the lift type and system fluid temperatures will be key to making sure paraffin products are placed up stream of where a potential paraffin issue may occur, as WAT will be the greatest driving factor for paraffin related issues, variables such as API that will impact the natural solvency of the crude and percent wax should also be considered. The Avalon and Wolfcamp formations can have paraffin deposition given the elevated risk for other solids, paraffin treatment in these formations will have to be addressed on a case by case basis.

The pronounced tendency for the Wolfcamp formation to form acid soluble iron compounds compared to the Bone Spring and Avalon formation is interesting. Understanding where the H_2S and available iron is coming from is necessary for a complete understanding of how to minimize this risk. Is there a formational iron component? Is the iron coming from corrosion? Could MIC be contributing to the available H_2S? Does the lower M-alkalinity in these waters make the brines more corrosive and result in less carbonate scale? These are all questions to ask given the water chemistry presented in Table 1, where relatively low levels of dissolved H_2S and variable iron content are shown to be present in the waters. Variable iron content could obviously be a results of solid precipitation out of the fluids before the sample point. This then brings up questions about if iron trends can effectively be used to track general corrosion well in the Wolfcamp formations.

In the Northern half of the Delaware Basin, paraffin, carbonate, acid soluble iron compounds and acid insoluble compounds are the most common types of oil field solids. Further work is needed to break down the acid insoluble category. Of course, the "acid insoluble category" can include silica oxides but also more problematic scales such as barium, strontium, calcium sulfates. Visual examination and field performance history indicate that the acid insoluble solids here are mostly likely related to silica dioxide frac sand.

While data presented here may not have been the root cause of a failure, it was recovered from a system with the associated formational fluids. Typically, the greater the volume of solid formed the more likely it is to cause issues. Further, where a solid is found in a system will effect location of the chemical or mechanical treatment strategy put in play. Lift type, pressure drops, location in decline curve, velocity of fluids, oil water ratio, the age of the well, microbial activity all have the potential to impact the potential for solid deposition by changing the system. Further work is needed to understand how and if the above variables effected these formational trends. It would also be interesting to establish formational geographic trends if any exist, closer to the shelf and in the Southern Delaware Basin.

Conclusions

As data continues to be gathered and categorized, the trends in the solid data presented here provide a formation based, data driven road map that will aid operators in designing solid risk mitigation and treatment strategies. Preliminary treatment results on approximately 100 Northern Delaware Basin locations using insights from this dataset has resulted in zero chemical related failures. These data trends combined with optimization efforts, have the potential to provide powerful proactive cost savings for Northern Delaware Basin operators, reducing downtime and additional financial burdens associated with work over costs and deferred production.

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