AADE-24-FTCE-090

Assessment of Sized-Salt Systems and Their Application in Completions and Workovers

Kimberly Dobson, Kim Tresco, Leslie Escobar, TBC-Brinadd, LLC; Raoul Razzouk, Energy Middle East; and Johnnie Cohorn, Consultant

Abstract

Workovers are performed to achieve a variety of objectives, including re-perforating damaged zones, perforating new zones, and isolating existing zones, and even relatively short sidetracks. In most cases, it is more cost-effective to work over an existing well than to drill a new well.

However, some workovers pose a higher risk of fluid loss, which in turn can yield wellbore impairment, incremental operational costs, excess brine volume usage, and production deferment (Hussein, 2022; Fonseca, 2023). Excess fluid loss alone can impart formation damage, requiring unplanned time to produce the working fluid that was lost to a zone or reservoir during a well intervention. A workover executed such that losses are minimized during the operation historically cleans up within the planned AFE upon start-up thus avoiding unplanned costs.

This paper presents case studies of multi-component sized-salt systems used historically in workovers where formulation achieved fluid loss control, with deposition and sealing of the planned medium thus minimizing damage as associated with excessive skin. These filtercakes deposit and bridge across a relatively wide range of permeable rock even relatively small fractures and sand control screens thereby reducing its permeability rapidly.

This paper focusses on higher density applications where modifications were incorporated for higher temperature situations and provide compatibility with the required higher density base.

The multi-component sized-salt system has been applied in West Texas, Gulf of Mexico, California, Egypt, and Middle East. These results have alleviated the need for post intervention, kept within their planned costs, and returned to production near or at the original production rate, suggesting little to no permanent reduction of target reservoir permeability.

The higher density system will be contrasted with respect to rheology, fluid loss, thermal stability, and formation damage for each application discussed.

Introduction

Classic evaporites and their inherent minerals – specifically halite, potash, and sylvite – are utilized in the oilfield and blended with water to produce monovalent brines, whereby densities as great as 10.0 lb/gal can be achieved. However, solid salt, specifically halite, encompasses a relatively wide range of use and applications. For example, a supersaturated brine of halite can be used as an agent for bridging formations (e.g., perforated zones or open-hole), an agent to bridge inside sand control screens, bridging a zone after conventional fracturing, to divert fluids during unconventional fracturing operations, and as a bridging blend of a drilling fluid used for injectors, to name a few uses. As an example, workover interventions often require fluid loss control, especially when the formation pressure of a zone has been depleted significantly (Hussein, 2022). In these operations lack of or inadequate fluid loss control not only increases the risk of formation damage, but inflates the operational costs and potentially delays production.

While the use of salts to produce a brine is nearly as old as the oilfield itself, the use of solid halite to serve as a bridging agent in a fluid system or a fluid loss pill for the aforementioned uses was introduced in the mid to late 1970's (Mondshine, 1977, 1981). The concept of grinding halite to specific sizes was introduced whereby these grades yielded particle size distributions to form bridges over a relatively wide range of pores or openings thereby enhancing the deposition of a filtercake such that its permeability was relatively low. Subsequently, these grades were blended with polysaccharides and buffers to create additional functionality.

In addition, a salt-solubility curve was introduced which served to mitigate dissolution of the bridging particles so that they maintained their initial size further enhancing bridging and sealing of the target medium over temperature and time. Introduction of a salt-solubility curve for specific salt concentrations of saturated various brines, for example divalent calcium chloride, expanded the ability to apply sized salt in scenarios where greater density was required. This enabled the formulation and use of sized blends for bridging and sealing at relatively higher densities, for example greater than 14.0 lb/gal.

Where removal or cleanup of the residual filtercake is desired, undersaturated brine can be used (e.g., seawater), a light-density brine, or a produced fluid as these will initiate dissolution of the residual salt (Mondshine, 1981). It follows that the salt and polysaccharide systems are soluble/dispersible in these fluids thus reducing risk of formation damage from the aforementioned fluids. Rather upon contact with the formation and with time, they will initiate dissolution of the residual filtercake in the near wellbore.

Furthermore, internal breakers, such as peroxides, were introduced that would remain inactive when incorporated as a component of a drilling fluid or fluid loss control pill until activated by a low-pH catalyst fluid (Dobson et al., 1995). The sized salts in the drilling fluid or pill are deposited with the residual filtercake. Once activated, the peroxide radicals attack the glycosidic linkages that are common with polysaccharides. Of note is the use of enzymes, where applicable (Battistel et al., 2005, Al-Taq et al., 2023), and inorganic and/or organic acid blends are also effective.

The utility of halite can be summarized as:

- **Blending of brines:** either as a base or working fluid or supersaturate a monovalent or divalent brine
- **Creating bridging agents:** ground to specific size and distribution subsequently coated for anti-caking whereby the combination of these sized grades can be combined to further create a specific particle size distribution to bridge and seal a formation matrix or a sand control screen
- **Operational uses:** when combined with polysaccharides and buffers, halides create fluid loss systems for application to mitigate losses after drilling or completions such as controlling losses after perforating, gravel-packing, fracturing or after running sand control screens. For workovers, it prevents losses to depleted zones.
- **Mitigate damage due to excessive skin:** the residual filtercakes are removed with undersaturated brines where applicable. A peroxide can be incorporated to enhance dispersion and dissolution of the residual filtercake as can external application of inorganic and/or organic acid.

The following sections discuss the sources and types of salt, their preparation for use, and their incorporation into systems. The case histories compare earlier applications whereby relatively low density pills were prepared and utilized to more recent high density applications and their use. Of note is the savings with respect to time required to return a well to production, cost savings, and production gains when this information was shared.

Sources and Purity of Salt

Oilfield salt, specifically solid halite, is sourced using three techniques: evaporators (e.g., rapid heating and open-pan methods), underground mining (e.g., shaft) or surface mining (e.g, playas), and solar drying via man-made lakes.

Evaporators and solar drying require a source of brine; the more saturated the brine, the more dry salt that is produced per volume. When evaporators are used, the source brine can be created by pumping fresh water down a well that has penetrated a known evaporite. The fresh water dissolves the inherent salt(s) on contact and with time produces a near-saturated brine. However, the final saturation is dependent on the contact and time as well as the purity of the evaporite itself. Solar techniques are also dependent on a source of saturated brine. Some of these operations source the brine from sea water, saline lakes (i.e., terminal lakes), or water used in mining operations that separates the uneconomic fraction (gangue) of an ore from the more valuable fraction, consequently this water incorporates evaporite minerals (e.g., potash mining).

Underground and surface mining exploits evaporites whereby the term "rock salt" is typically applied to the final product. The final product as produced from evaporators is referred to as "evap", or alternatively, evaporated oil well drillers salt (EOWDS).

All three sources and methods yield salt of varying purity (Tables 1, 2 and 3). Evaporators typically yield the purest salt with respect to halite, approximately 99.9% wt/wt. Halite as mined rock salt can range from 88% to 96% wt/wt where the non-halite phases can comprise combinations of silica, calcium carbonate, calcium sulfate, and varying clay minerals. Halite produced as solar evaporated can range from less than 70% to 95% halite. The non-halite phases of evap can comprise sulfates such as magnesium, sodium, and calcium as well as potassium chloride in addition to minor amounts of silica and clay. The latter may be incorporated from the solar pond itself, however, the percentages are relatively minor.

Table 1 – Composition of Selected Rock Salt

Type	Halite	Anhydrite	Quartz	Sylvite	Calcium Carbonate
Rock Salt[1] 1,200 ft. (Hockley, TX)	92-96	1-2	1-2	<1.0	1 - 4
Rock Salt[2] 2,889-4,068 ft. (Saltville, VA)	98.3-99.3	0.3-0.7	<1.0	0.3-0.8	<1.0

1. *Bulk X-ray Diffraction*
2. *Calculated from Mineral Log*

Table 2 – Composition of Selected Solar Salt

Type	NaCl	KCl	$MgCl_2$	$CaCl_2$	$MgSO_4$	$CaSO_4$	Na_2SO_4
Solar Salt 2020 Mo Avg. (New Mexico)	92.9	6.1	<0.1	0.0	0.5	0.1	0.3
Solar Salt 2019 Mo Avg. (New Mexico)	90.1	8.0	<0.1	0.0	0.9	0.1	0.9

Table 3 – Composition of Selected Evaporated Salt

Type	Na	Ca	Mg	K	SO_4	Cl^-	Si
Brine[1] 2018 (M. Belvieu)	3600.3	19.6	0.4	2.1	21.5	3682.9	0.2
Type	**NaCl[2]**		**$CaSO_4$[2]**		**Ca and Mg (ppm)**		
Evaporated Salt	99.85 - 99.99		0.04 – 0.01		2 - 30		

1. *meq/kg*
2. *wt%*

These compositions and ranges serve as a guideline or reference. Note that the final product, may not comprise 100% halite, however these sources of salt are typically greater than 99% soluble regardless of the abundant evaporite minerals (Figure 1) and are readily soluble in various acids, undersaturated brines, and fresh water. As the aforementioned discussion advocates, halite sourced as rock salt or evaporated salt comprises a greater percentage of halite and are the preferred sources for manufacturing grades of specific sizes. Sources of solar salt, depending on purity, specifically the concentration of potassium chloride, may function as a shale inhibitor, however the concentration of sulfate must also be considered when applied to oilfield drilling and completions. The next section details the particle size range and preparation of these salts.

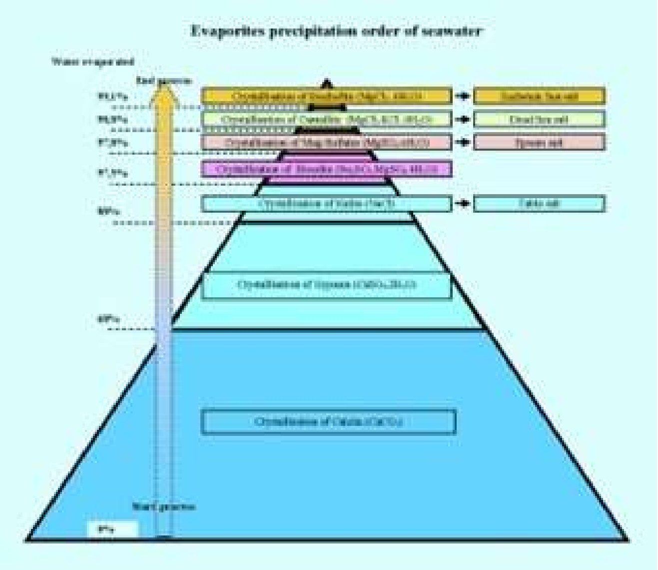

Figure 1 – Evaporite sequence (Repiotraschke).

Preparation of Salt Grades and Blends

Rock and evaporated salts can be used to produce specific grades that range from less than 5 µm to as large as 2.75 mm where both values are representative of a d_{50}; however the d_{90} of the larger grades can approach 10 mm. Note that salt or any particle of this diameter poses risk of plugging valves, tools, even the jets of a bit, especially when combined with other particles. Typically, evaporated salt is used to create finer grades where the median size is less than 300 to 400 µm, however some evaporators produce crystallized salt less than 30 to 40 µm. These grades are treated with yellow prussiate of soda (YPS) to mitigate "caking" thus enhancing their flow-ability from associated packaging. For grades with a larger d_{50}, up to 0.5 – 1.0 mm, rock and evaporated salts can be combined. Salt grades larger than 1.0 mm typically comprise only rock salt. This is primarily due to the ability of an evaporator to produce particles of salt larger than 0.5 mm. Note that particles of salt with diameters greater than 0.25 mm are less prone to congeal and solidify, thus anti-caking agents are not typically applied.

Combining the sized salt at specific ratios or grinding only one source to a specific particle size distribution (PSD) promotes functionality for drilling systems or fluid loss control. When packaged grades are combined at selected ratios, they further enhance the ability to create specific bridging blends. These can be used to bridge or seal a target medium (e.g., matrix of a formation, gravel, and small fractures). As an example, Figure 2 shows PSD of blends created using manufactured grades of salt, subsequently optimized such that their combined PSD effectively bridges the gravel mesh and fracture widths shown. Note that the d_{50} of the blends for the gravel was optimized to the median opening of each gravel mesh however the d_{90} of the PSD for the fractures was optimized to bridge at 90% of its width.

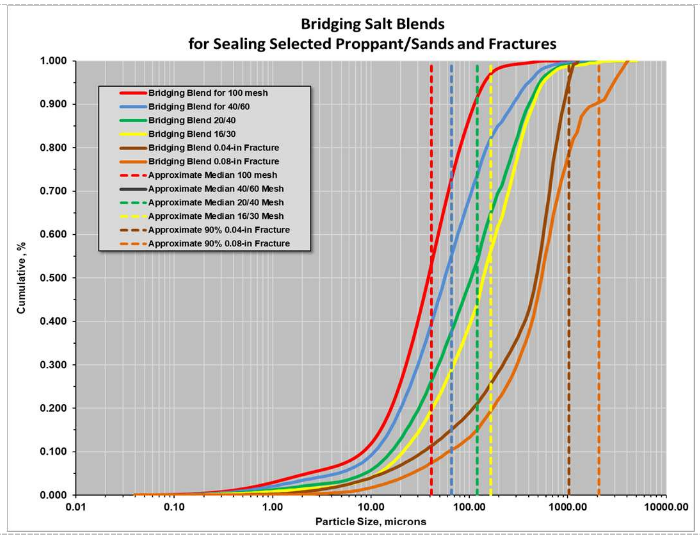

Figure 2 – Using rock and evaporated salt grades, PSD were optimized for bridging and sealing various gravel and fractures.

Basics of Salt-Based Systems

The initial concept of utilizing salt and/or salt-based systems in drilling, completion, or workovers has evolved since its introduction in the mid-seventies. Two systems: a low-density salt system (LDSS) and a high-density salt system (HDSS) were since developed and have been utilized successfully in all these phases. The development of these systems was predicated upon the combination of a viscosifier, filtrate reducer, and bridging solids versus using only a viscosifier and bridging solids. The aforementioned was found to enhance fluid loss control and return permeability (Mahajan and Barron, 1980). To further, the inherent polysaccharide in both systems has improved, especially when utilizing a divalent brine as a base, as this component is significant with respect to compatibility, controlling fluid loss, and generating viscosity. Table 4 shows the basic components of these two systems and subsequently their differences. Note that the density boundary between a LDSS and HDSS is arbitrary as calcium chloride can be utilized as a base in both systems**;** however**,** monovalent brines are typically used for the LDSS and divalent for the HDSS. All salt grades can be incorporated into both systems to enhance bridging**;** however, both systems require super-saturation. This concept will be expanded in the following section as well as elaborating the key mechanisms necessary for preparing and utilizing these systems and their key differences.

Table 4 – Typical Components of LDSS and HDSS

LDSS	HDSS
Base	
Monovalent brines Up to 10.7 lb/gal $CaCl_2$	Divalent brines $CaCl_2$, $CaBr_2$, $ZnBr_2$
Internal	
Derivatized starch Sized salts Viscosifier Magnesia compound	Cross-linked starch Sized salt Magnesia compound
External	
Sized evaporated salt Sized rock salt Scavengers Anti-foamer	Sized evaporated salt Sized rock salt Scavengers Anti-foamer

Supersaturating

LDSS are typically mixed using a saturated sodium chloride brine as a base, thus an initial density of 10.0 lb/gal whereby the addition of salt grades, depending upon the concentration, will increase the final density of this system. HDSS are mixed using a divalent base that is typically not saturated and again selected salt grades are added that increase the final density of this system. For both, these salt grades serve two purposes: increase density and as previously discussed, their combination enhances bridging. However to ensure that the selected salt grades do not dissolve, either partially or entirely, additional salt must be incorporated. This addition ensures that the selected base is saturated with respect to the maximum density as well as super-saturated with respect to temperature. The latter ensures that the selected bridging salts do not dissolve when these systems are exposed to downhole temperature (Figure 3). Thus, with elevated temperatures, the water fraction of the base supersaturates whereby only 5 lb/bbl of additional salt will dissolve into saturated NaCl as temperatures increase from atmospheric to 250°F (Mondshine 1977, 1981, 1986). In addition, filtration data show that a system formulated as such is thermally stable to temperatures up to 320°F (Table 5). Super saturation occurs when additional salt dissolves into a quantity of water or brine than it can intrinsically dissolve at standard temperature (i.e., the concentration of a solute exceeds the concentration specified by the value equilibrium solubility). Note that the additional sodium chloride is a very-fine grade thus ensuring preferential solubility versus the coarser bridging grades. When incorporating sodium chloride for super-saturation, the use of very-fine particles, i.e., less than 20 µm, ensures that these particles dissolve preferentially to larger particles. This is primarily due to the increased surface area (Thompson, 2023).

Saturation and super-saturation data have been developed and tabulated for other brines, for example, approximately 18 lb/bbl of additional sodium chloride which will super-saturate a 10.7 lb/gal $CaCl_2$ brine. Thus, sodium chloride is the preferred salt for incorporating into brines such as potassium chloride, sodium bromide, calcium chloride, calcium bromide, and 10.7-lb/gal $CaCl_2$ brine. Thus, sodium chloride is the preferred salt for incorporating into brines such as potassium chloride, sodium bromide, calcium chloride, calcium bromide, and combinations thereof thereby ensuring both saturation and super-saturation of the water phase (Table 6).

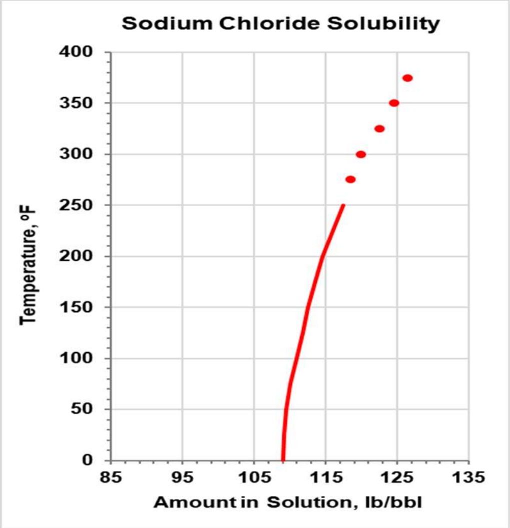

Figure 3 – Solubility of sodium chloride versus temperature. Only nominal increases are realized with sodium chloride brine exposed to increasing temperature (Mondshine, 1977).

Table 5 – Filtration Data of Size Salt Pill at 320°F

HTHP: 320°F, 500 Differential PSI, 50 mD Saturated Aloxite Disk	
Spurt (ml), actual	3
30 min (ml), actual	8.5
16 hr min (ml), actual	20
24 hr min (ml), actual	20
48 hr min (ml), actual	27

Table 6 - Maximum Applications of Salt Systems

Parameters	LDSS	HDSS
Temperature:		
BHT °C (°F)	160 (320)	165.6 (330)
Concentration:		
Typical Primary Internal (lb/bbl)	40-80	80-100
Additional External (lb/bbl)	Up to 195	50-125
Total Loading (lb/bbl)	Up to 270	Up to 225
Base Brine:	Monovalent and $CaCl_2$	Divalent $CaCl_2$, $CaBr_2$, $ZnBr_2$
Base Density:		
NaCl (lb/gal)	10.0	n/a
NaBr (lb/gal)	12.5	n/a
$CaCl_2$ (lb/gal)	10.7	11.5
$CaCl_2$-$CaBr_2$, $CaBr_2$ (lb/gal)	n/a	14.3
Three-salt blends (lb/gal)	n/a	17.5 & 18.5[1]
Pilot Testing and Field Application:		
Differential (psi)	2600	4000
Type Media	Formation, Screen, Gravel	Formation, Screen, Gravel

The use of sodium chloride to saturate formate salts is not recommended as relatively large amounts of halide ions can promote corrosion. However, sodium formate is compatible while potassium formate is not (Sinomine, 2022). As each application is unique, pilot testing is highly recommended.

Formulating Salt Grades

Until 1968 various grades of rock salt were used without extensive consideration for particle size distribution (Mondshine, 1981). As the pore size for matrix type formations as well as other mediums such as gravel, fractures, sand control screens, etc., vary considerably, especially from well-to-well or application-to-application, the use of a specific particle size distribution can only enhance fluid loss control when applied. Thus, combining specific salt particles with polysaccharides and colloidal dispersants creates a system that further enhances the ability to control fluid loss. It is well known that other inorganic materials can also be utilized, such as calcium carbonate or magnesium oxide. All of these materials provide the ability to create unique distributions when ground to a target size. Typically the mass-median-diameter, for example the d_{50} or the cumulative frequency of 50%, is used in particle size distribution measurements to define a preferred target of a selected material after grinding and sampling.

Components

To enhance the system's suspension and fluid loss control properties, it incorporates a blend of cross-linked hydroxypropylated starch and xanthan gum. These biopolymers work in tandem, preventing settling of the bridging solids and reducing fluid loss while minimizing the risk of formation damage (Stagg et al., 1986; Bennett, 1988; Mondshine, 1989). The salt system is designed to create a balance between effectiveness and ease of use to optimize performance including:

- **Low Biopolymer Concentration:** minimizes the potential for formation damage while still maintaining adequate viscosity and fluid loss control. These components are ccompatible with various brines. Temperature stability is maintained with the addition of buffers and scavengers. The bridging solids remain suspended and maintain their effectiveness even at temperatures up to 320°F.
- **Thin and Removable Filter Cake:** The system deposits a thin filter cake with relatively low permeability, minimizing production impact and allowing for easy removal with water or undersaturated brine.
- **Low-Pressure Cleanup:** The filter cake can be readily cleaned up with as little as 5-psi differential pressure, simplifying post-intervention operations. The salt system can be customized depending on the specific wellbore conditions and challenges. It can be readily mixed with various saturated brines beyond sodium chloride, making it a highly adaptable solution for diverse workover applications.

Low-Density Salt System (LDSS)

Ideal for low-pressure formations and sensitive reservoirs, these pills boast densities between 10.5 and 13.5 lb/gal. This closely matches the density of many formation fluids and completion brines, reducing differential sticking and formation damage. Their unique composition promotes rapid dissolution after the operation, minimizing environmental impact and simplifying clean-up. LDSS demonstrates excellent bridging properties under simulated conditions, making them a promising option for low-pressure bridging needs.

The use of fine particles reduces polymer concentrations and improves sealing characteristics over a relatively wide range of permeability. In this manner, the system deposits a filtercake whereby the finer particles seal openings created by the larger particles, a cascading process whereby a filtercake forms very rapidly and ultimately seals the target medium. The relatively low polymer concentration and combination is synergistic and creates a gel structure which generates low-end viscosity to support bridging particles which imparts long-term suspension and stability. The temperature limit can be extended to as high as 325°F by incorporating thermal stabilizers. Overall, this promotes the deposition of a relatively thin and relatively low permeability filtercake

High-Density Salt System (HDSS)

Designed for high-pressure and high-temperature environments, these pills exhibit densities exceeding 12.5 lb/gal. Their robust structure effectively bridges across large intervals and withstands demanding downhole conditions. Notably, their composition ensures controlled dissolution rates, allowing for extended bridging performance when required. HD sized-salt pills have proven their efficacy in laboratory and field trials, solidifying their position as a reliable solution for challenging downhole scenarios.

By offering LD and HD options, salt pill technology provides a versatile bridging toolbox for operators. Selecting the appropriate density range based on specific downhole conditions ensures optimal performance, minimizes formation impact, and promotes efficient and environmentally conscious workover operations.

Preparation and Testing of Salt Pills

The sized-salt systems can be blended into monovalent or divalent base brines. These brine solutions are saturated with EOWDS to ensure base brine saturation and bottomhole temperature saturation. All components are mixed on a multimixer at low speed for a designated time. After mixing all components, rheological properties are measured at either 78°F or 120°F. Note the initial rheological properties are recorded without the coarse salt grinds as these relatively larger salt particles interfere with the rotating sleeve of a standard rheometer. To assess thermal stability, aging cells are utilized and removed from the forced air draft oven after the required static aging time requirement, which can range from sixteen hours up to seven days.

Sized-salt systems rheology exhibit Yield Point (YP) that are typical for fluid loss pills (i.e., inverted where YP>PV and the YP/PV ratio ranges from 2:1 to 3:1) thus ensuring that solids remain suspended. In addition, their 10-sec/10-min gel strengths are not exceedingly progressive thus will impart relatively low surge and swab pressures.

Fluid loss simulations are performed using respective filtrate media whereby the matrix equates to target medium (e.g., matrix of a formation, gravel, and small fractures). Fluid loss tests are performed using 500-psi differential at the bottomhole temperature ensuring low spurt loss and maintaining stable fluid loss control over the designated filtrate time. A sized-salt pill tested at 200°F measured less than 8 mL fluid loss and another, also tested at 250°F, measured less than 6 mL fluid loss after 10 minutes of initiating the filtrate test. As a reference, water-based drilling fluids are typically optimized to attain less than 8 mL after 10 minutes to ensure effective initial bridging is achieved.

Formation Damage

Formation damage is a significant concern during well completion operations. When drilling fluids and completion fluids invade the formation rock, they can plug the pore spaces, hindering oil and gas flow and reducing well productivity. Starch is a common component of drilling fluids that can be particularly damaging if not properly removed (Battistel, et al., 2005).

Starch is often added to drilling fluids for fluid loss control. However, starch can migrate deep into the formation during wellbore operations and become problematic in several ways:

- Starch particles can physically plug the pore throats within the formation rock, significantly reducing permeability to oil and gas.
- Starch can act as a sticky trap for other formation damaging materials like drilled solids or clays, further restricting flow.
- Starch can provide a food source for bacteria in the formation, leading to their growth and multiplication. This bacterial activity can generate biomass that further restricts flow paths.

As filtercake removal is important, oxidizers and enzyme breakers are typical technology for efficient cleanup. Peroxides are oxidizing agents that can chemically break down starch molecules into smaller, less damaging components. Their effectiveness depends on factors like the type of starch, concentration, and downhole temperature. Enzymes are biological catalysts that can specifically target and break down starch molecules. Enzymes are more targeted for degradation of starch and generally less corrosive to wellbore equipment. Enzymes are effective at lower downhole temperatures as compared to some peroxides. Enzyme breakers can be more expensive than peroxides and may be susceptible to deactivation by certain downhole conditions like high salinity or contamination.

Permeability testing is a crucial step in evaluating formation damage and ensuring well productivity. The return permeability test is conducted at high-temperature and high-pressure conditions on cores. A quantitative value of percentage of return is often used to provide insight on potential formation damage.

It is important to note that selecting the most appropriate formation damage cleanup method depends on various factors specific to each well, including the type of starch used, formation characteristics, and downhole conditions. Consulting with engineers and reservoir specialists is essential to design an effective cleanup strategy.

Field Difficulties and Intricacies

One problem experienced with sized-salt systems as used for workovers has been the number of pills required before an acceptable loss rate is realized (i.e., less than an established trigger rate). Field results show variation from field to field as well as workover to workover. While the traditional problems with quality control, especially when mixing on remote sites, is eradicated with preparation and supervision, one root cause that has been identified is pill dilution associated with relatively high loss rates and spotting a pill too far above the problem zone. The latter cannot always be avoided however, the former is alleviated with greater pill viscosity such as shown in Table 7 for LDSS and Table 8 for HDSS and/or incorporation of a viscous spacer. Thermal stability can eliminate the potential use of these systems as pilot testing or laboratory simulations provide relative results that are indicative and conclusive. When thermal stability is identified as a risk for failure of any pill or system that incorporate polysaccharides, the time as well as temperature should be considered. While static pilot testing of salt systems at temperatures of 300°F and greater for a period of days to weeks degrades the polysaccharide components, the use of buffers and scavengers can delay the degradation.

Table 7 - Rheology Targets for LDSS

Rheology	72 to 78°F	@ 120°F
600/300 rpm Reading:	62-66 / 45-49	52-56 / 39-43
200/100 rpm Reading:	38-42 / 30-34	35-39 / 28-32
6/3 rpm Reading:	12-16 / 11-15	13-17 / 11-15
PV (cP) / YP (lb/100 ft^2):	15-19 / 28-32	11-15 / 26-30
10-sec / 10-min Gel (lb/100 ft^2):	11-15 / 11-15	11-15 / 12-16
Direct pH:	7.0 – 9.0	7.0 – 9.0

Table 8 - Rheology Targets for HDSS

Rheology	@ 120°F
600/300 rpm Reading:	130-140 / 75-85
200/100 rpm Reading:	55-65 / 35-45
6/3 rpm Reading:	10-20 / 10-20
10-sec / 10-min Gel (lb/100 ft^2):	10-20 / 10-20
PV (cP) / YP (lb/100 ft^2):	50-60 / 20-30
pH:	7.0 – 8.0

Case Studies – HDDS

GOM Case Study 1

This case study examines the use of a HDSS during the completion of an oil well located in Gulf of Mexico on Ewing Bank in July 2021.

A major Operator wanted to complete a reverse drill out using 15.9-lb/gal zinc bromide brine ($ZnBr_2$) from the wellbore. A HDSS was recommended to spot in the perforation zone. Additional pressure was added to squeeze the pill into the formation to enhance wellbore stability. The crew removed the drillwater and existing $ZnBr_2$ brine from the wellbore using a reverse circulation technique. This involved pumping fluid down the annulus and recovering it from the production tubing. During this process, any encountered hydrocarbons were captured. A 25-barrel HDSS was pumped with 7 bbl spotted above the circulating valve. The well was cycled on vacuum, the pill falls into perforations. Then, pressure was applied three times at 950 psi to squeeze the pill contents into the formation. After squeezing the pill, the crew pulled out two stands of drill pipe and monitored the well's static pressure. Subsequently, they circulated a full volume of fluid down the workstring, again capturing any hydrocarbons at the bottom. The perforating equipment was disconnected and removed from the wellbore. There was no need for additional wellbore cleaning (slugging) as the wellbore fluids were considered balanced.

GOM Case Study 2

A major Operator utilized a HDSS for Screen Sealing. The objective was to seal an 8-gauge wire-wrap screen in an offshore well located in Gulf of Mexico in Walker Ridge Formation during a workover operation. The completion fluid used a 18.5-lb/gal $ZnBr_2/H_2O$ brine. The bottomhole temperature (BHT) was 245°F. A 100-lb/bbl HDSS was pumped to seal the screen and additional additives were added for thermal stability. The HDSS components were added sequentially to the brine following a specific mixing schedule to ensure proper hydration and effectiveness.

The HDSS was successfully pumped downhole and into the 8-gauge screen. Increased pump pressure indicated successful placement of the sealing material. The seal remained stable for 48 hours before being produced back, demonstrating the system's effectiveness.

GOM Case Study 3

Gravel packing is a critical procedure used to prevent formation sand production in oil and gas wells. It involves placing a layer of gravel around the wellbore screen to prevent sand from entering the production stream and potentially damaging downhole equipment. However, maintaining wellbore stability during the process can be challenging, particularly in offshore environments.

This case study explores the successful application of HDSS, to facilitate gravel packing operations in East High Island block, offshore Texas.

The operator opted to utilize HDSS, designed to temporarily seal perforations and control fluid loss during gravel packing operations.

The gravel packing procedure involved the following steps:

1. Perforation and cleanout: The well was perforated, and HDSS was spotted downhole to cover the perforated interval and provide an additional 10 barrels of sealing volume.
2. Gravel pack placement: After wellbore cleanup, a sand and gravel pre-pack was placed in the perforations, followed by a 3-5 barrel HDSS to retain the gravel and limit fluid loss.
3. Screen and liner installation: A screen and liner were run and followed by a gravel pack. Another 3-5 barrel HDSS was added if fluid loss occurred.
4. Production string installation: Following the gravel pack, a final 3-5 barrel HDSS was spotted to control fluid loss before running and nippling up the production string.
5. Well clean-up and production: The well was then produced for clean-up, allowing the HDSS pills to dissolve and restore full wellbore flow.

The use of HDSS proved to be successful. The procedure encountered minimal fluid loss, enabling efficient placement of the gravel pack and screen assembly. The operator reported high satisfaction with the results and plans to implement this technique on future wells encountering similar challenges.

Case Studies – LDDS

West Texas Case Study

A major Operator was experiencing difficulty working over wells in West Texas. The problem was that the two formations, the Fusselman and Ellenburger carbonate formations, were extensively fractured and acidized, and there was communication between the two formations. This meant that when the bottom tubing or packer was pulled, pressure from the higher zone would flow into the lower zone, making it impossible to hydrostatically balance the pressure in both formations simultaneously.

The operator was planning to work over another well in the area and requested a solution to these downhill problems. The well had also experienced severe scaling and corrosion of the production tubing by produced carbon dioxide, making it imperative to replace the tubing. Prior to the workover, the tubing to the Ellenburger formation had become plugged. To unplug the tubing, production personnel pressured it to 7,500 psi, but the pressure suddenly dropped to zero. It was believed that this pressure had burst or split the tubing.

An LDSS sized-salt system was recommended, to temporarily seal the perforations in the casing. Lab tests confirmed that the **LDSS could seal holes up to half an inch in diameter**. A 50-bbl LDSS was recommended.

The LDSS was mixed using a mixing tank in a vacuum truck prior to addition. The well was then killed with 9.1-lb/gal brine. Once the well was on vacuum, 10.0-lb/gal brine was pumped down as a spacer. LDSS was then added as the system was pumped downhole. The extra coarse sized-salt was added to the pill to maximize the amount of product reaching the perforations.

The pressure was increased to 1,500 psi and held for a period of time. Once the work over operations were completed, the pressure was bled off to zero and the well was shut in to wait for a rig.

After the workover operations were completed, production from both zones returned to 100%. The upper zone was immediately productive, while the lower zone took two weeks to come back on production. The operator was pleased with the results.

Offshore California Case Study

An LDSS was utilized during a specialized workover technique for killing wells and changing electric submersible pumps in the Up-Ford and Terminal formations, offshore California. These formations contain water sensitive sands which are easily damaged by liquid invasion during workovers.

A number of special design issues had to be addressed to ensure success of this operation in the field:

- Could a sized-salt pill be spotted through coiled tubing and pass through a slotted liner to seal an openhole completion (Figure 4)?

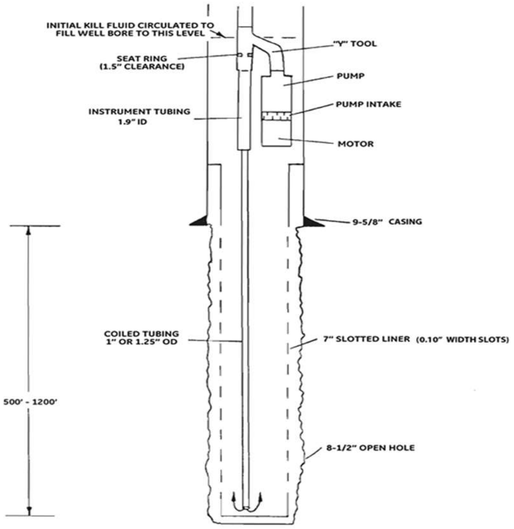

Figure 4 – Typical Up-Ford completion with proposed coil-tubing kill.

- On an openhole gravel pack completions, would the sized-salt pill pass through a slotted liner and coarse gravel pack sand to seal on the formation (Figure 5)?
- Once the sized-salt pill had been placed and a seal achieved, would it continue to prevent losses to the production zone throughout the workover?
- Could this procedure be handled in a safe manner, allowing the submersible pump to be removed and changed with the well bore remaining full of brine during the entire operation?
- Could the sized-salt pill be removed as the well is produced without plugging the new submersible pump?
- Would the sized sodium chloride/polymer filter cake be removed from the formation by differential pressure and dissolving, thereby allowing reservoir fluids to be produced as effectively as before the well failed?

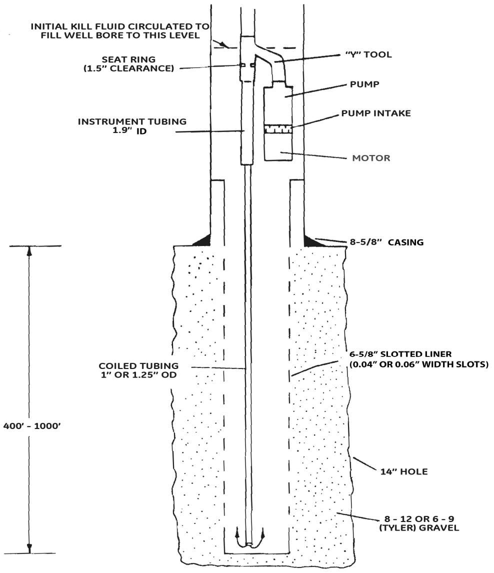

Figure 5 – Typical Terminal completion with proposed coil-tubing kill.

It was determined that the salt particles in the LD sized-salt pill could pass through the openings in the slotted liners and gravel pack sand with sufficient particle size to bridge the formation pore spaces, and subsequently flow through the diffuser/impeller of the submersible pump as the well is produced. The following sequence outlines the fluid loss pill placement and removal:

1. The blanking plug in the production screen was removed by wireline to allow access to the production zone
2. A coiled tubing string (1 inch or 1¼ inch) was placed and filled with 10% KCl
3. LDSS was circulated into the coiled tubing, displacing the 10% KCl, but not exceeding the total volume of the string
4. After reaching the total depth of the well, the remaining volume of LDSS was circulated to fill the well bore to the “Y” tool (Figures 4 and 5)
5. The coiled tubing was raised to submersible pump depth and any residual LDSS was displaced with 10% KCl
6. The coiled tubing, production tubing, and pumping equipment were removed from the well bore
7. A new pump was installed and the LDSS was produced from the casing and the face of the formation through the submersible pump

Prior to the new well kill and fluid loss control procedure, Up-Ford and Terminal zone wells which were damaged averaged a net oil production loss of 34%. After introduction of the new procedure using LDSS, numerous workovers have been conducted with net oil losses ranging from zero to only 5%.

Egypt Case Study

A major Operator required a re-completion process for well QASR-NE1X located in Egypt. The well initially produced from the U-SAFA Reservoir but due to declining rates, it was decided to switch production to the Paleozoic reservoir. It was also decided to re-complete the well rigless knowing the fact that the U-SAFA Reservoir contains a high-pressure differential of 3000 psi which would exceed the wireline tool capabilities. Attempts to close the sliding sleeve downhole (SSD) isolating the U-SAFA Reservoir in September 2013 failed.

The solution involved a multi-step process using various equipment and service companies:

- **Isolating U-SAFA with LDSS:** Pump a high-viscosity pill followed by a salt pill designed to cure losses into the U-SAFA reservoir. Squeeze the salt pill into the open perforations of the U-SAFA zone. Monitor pressure for several hours to ensure proper sealing.
- **Tubing Punching and Wellbore Access:** Mobilize a logging unit and tubing puncher tool. Punch a hole in the tubing above the existing plug to access the Paleozoic reservoir.
- **Well Testing and Production:** Perform a well test using a high-pressure testing package. Flow the well to a flare pit for cleaning and establish natural flow. If natural flow is not achieved, use nitrogen lift to initiate production. Conduct a production test for several hours.
- **Production Optimization:** Based on the test results, decide whether to install a separation sleeve to permanently isolate the U-SAFA reservoir.

This re-completion process successfully isolated the U-SAFA Reservoir and established production from the Paleozoic reservoir, leading to improved well performance.

Additional sized-salt pill successes are shown in Table 9.

Table 9 - Additional Sized Salt Successes in Egypt

Temp (°F)	Production Rate Before W/O (using salt pill)					Production Rate After W/O					Gains		
	TYPE	BFPD	W.C	BOPD	GAS	TYPE	BFPD	W.C	BOPD	GAS	BFPD	BOPD	GAS
290	ESP	**2237**	76	536.88	0.139	ESP	**5500**	89	605	0	**3263**	68.12	-0.139
290	LIFT	**162**	100	0	0	ESP	**636**	100	0	0	**474**	0	0
200	ESP	**822**	87	106.86	0.117	ESP	**1255**	95	62.75	0.031	**433**	-44.11	-0.086
290	N.F 32"	**389**	14	334.54	2.059	N.F 32"	**820**	25	615	2.627	**431**	280.46	0.568
290	N.F 23	**366**	0	366	0	ESP	**749**	33	501.83	0	**383**	135.83	0
290	ESP 16	**456**	0	456	0	ESP 128	**761**	0.7	755.673	0	**305**	299.673	0
250	LIFT	**1354**	34	893.64	0	ESP	**1640**	36	1049.6	0	**286**	155.96	0
200	N.F	**547**	0.4	544.812	0	N.F	**786**	7	730.98	0	**239**	186.168	0
220	ESP	**72**	6	67.68	0	ESP	**300**	97	9	0	**228**	-58.68	0
250	ESP	**1903**	95	95.15	1.049	ESP	**2124**	97	63.72	0	**221**	-31.43	-1.049

Middle East Case Study

A major operator faced a challenge when performing well interventions in sub-hydrostatic formations. These formations experience significant fluid loss, leading to wasted completion fluids, extended rig time, and potential formation damage. To address this issue, the operator explored innovative solutions and evaluated a LDSS designed to effectively control fluid loss.

The proposed solution was a unique salt pill, dissolvable in water, that temporarily plugs highly permeable zones within the formation, thus minimizing fluid losses during well interventions. The oil company conducted field trials in several wells to assess the effectiveness and impact of this technology.

Wells with historically high fluid loss during interventions were chosen for the trials. The LDSS was prepared according to a specific Standard Operating Procedure using 30 bbl of freshwater mixed with local, clean NaCl in a rig mixing tank with a reliable agitator until saturation was achieved (±10 lb/gal). Additional ingredients were added to reach a total volume of 40 bbl, including 5 bbl for dead volume.

The prepared sized-salt pill was bullheaded from the casing side (annulus) into the wellbore. The top of the sand formation was tagged with a scrapper, ensuring at least 50-ft clearance below the bottom perforations. The scrapper was pulled out of the hole (POOH) until a depth of 720 ft. The LDSS was bullheaded into the annulus: 10 bbl of high-viscosity fluid followed by 35 bbl of sized-salt pill at 3-5 bbl/min, then another 10 bbl of high-viscosity fluid behind. When the LDSS started sealing the perforations, fluid returned to the surface, indicating a 100% seal and allowing observation of the fluid level. The tubing side was closed, and ±10 bbl of the pill were squeezed into the perforations at a maximum surface pressure of 100 psi. The scrapper was run back into the hole (RIH) and used to clean the casing with saturated viscous brine (to avoid diluting the salt pill). The hole was circulated clean to the bottom. Cleanout was completed, the scrapper was pulled out while maintaining the well full by pumping 10-lb/gal brine to compensate for metal displacement volume. A wireline logging unit (WL unit) was rigged up, and a bridge plug was run in hole (RIH) to isolate the target formation.

The field trials yielded promising results: Both Well A and Well B showed complete elimination of fluid loss after deploying the LDSS, compared to 30 bbl/hr and 90 bbl/hr respective losses previously. Post-intervention well tests confirmed no decline in well productivity, and even indicated a slight improvement in one well. Reduced fluid loss translated to less completion fluid used, shorter flowback time, and faster oil production, leading to significant cost and rig time savings.

Conclusions

These case studies from various fields, spanning low-density NaCl brines to high-density ZnBr$_2$ brines, have showcased the effectiveness of these sized-salt pills in maintaining structural integrity and preventing fluid loss for workover operation across diverse regions and brine compositions (Table 10).

Sized-Salt pills key features are:

- The pill components deposit a thin and removable filtercake, effectively plugging even the tiniest fractures, and reducing fluid loss with optimal salt grinds.
- Designed for simplicity. Sized-Salt pills mix readily, pump smoothly, and circulate out effortlessly during cleanup. This translates to faster completion times and reduced operational burdens, putting the focus back on production.
- The multi-component sized-salt pills act as temporary filtercake dissolves readily, leaving minimal residue, and preserving the permeability of the reservoir.
- Sized-salt pills are compatible with standard water-based drilling fluid additives and various base brines.
- Sized-salt pills thrive in high-temperature and high-density applications and have proven efficacy in diverse regions like the West Texas, Deepwater Gulf of Mexico, California, Egypt, and Middle East.

This versatility establishes sized-salt pills as a valuable and reliable tool for operators seeking loss circulation solutions.

Table 10. Case Study Overview

Well #	Formation	Brine (lb/gal)	Pill Volume	TD (ft)	BHT (°F)	Loss Rate Worst Recorded	Loss Rate Stabilized
1	Ewing Bank	15.9 ZnBr$_2$	25 bbl	24000	278*	384 bbl/hr	Yes
2	Walker Ridge	18.5 ZnBr$_2$	100 bbl	21000	245	Uncontrolled	Yes
3	East High Island Block	12.2 CaBr$_2$	15 bbl	8000	225*	uncontrolled	Yes
4	Ellenburger/ Fusselman	10 NaCl	50 bbl	8500	130	uncontrolled	Yes
5	Upford	10% KCl	35 bbl	1200	110	34% Loss	Yes
6	Terminal	10% KCl	115 bbl	1000	110	34% Loss	Yes
7	Paleozoic	4% KCl	20 bbl	13702	290	uncontrolled	Yes
8	Umm Niqa	10 NaCl	35 bbl	1374	100	236 bbl/hr	Yes
9	Umm Niqa	10 NaCl	35 bbl	1374	100	236 bbl/hr	Yes

*computed

Acknowledgments

The authors would like to thank the management of TBC-Brinadd LLC for their permission to publish this paper and Energy ME and Johnnie Cohorn for their case histories. Many thanks to the chemists at TBC Brinadd for their due diligence and assessments. Many thanks to Mark Luyster for his mentorship. In addition, we graciously acknowledge the efforts and patience of Mary Dimataris for her technical critique, editing and formatting this manuscript.

Nomenclature

AFE = *Authorization For Expenditure*
BFPD = *Barrles Fluid per Day*
BHA = *Bottomhole Assembly*
BHP = *Bottomhole Pressure*
BHT = *Bottomhole Temperature*
BOPD = *Barrels of Oil per Day*
EOWDS = *Evaporated Oil Well Drillers Salt*
Evap = *Product produced from evaportators*
GOM = *Gulf of Mexico*
LCM = *Lost Circulation Material*
LDSS = *Low-Density Salt System*
HDSS = *High-Density Salt System*
MD = *Measured Depth*
MW = *Mud Weight*
NPT = *Non-Productive Time*
PSD = *Particle Size Distribution*
POOH = *Pull Out Of Hole*
PV = *Plastic Viscosity*
RIH = *Run in Hole*
SSD = *Sliding Sleeve Downhole*
TD = *Total Depth*
TIH = *Trip in Hole*
YP = *Yield Point*

References

Al-Rashidi, H., Jamal, M., Duncan, B., Al-Mousawi, A., Al-Sagheer, A., Al-Mosaileekh, S., Al-Husaini, M., and Ali, M., 2019. "Wells Intervention Cost Optimization Through Curing Formation Damage in Sabriya Wells – Case Study from Kuwait.:" SPE Kuwait Oil & Gas Show, Mishref, Kuwait, October 13-16, 2019. SPE-197992-MS. www.doi.org/10.2118/197992-MS

Al-Taq, A.A., Al-Ibrahim, H.A., Alsalem, A.A., and Alrustum, A.A. 2024. "Enzyme-Based Cleanup Fluid for High Temperature Filtercake Removal Applications." SPE/IADC Middle East Drilling Technology Conference, Abu Chabi, UAE, May 23-24, 2023. SPE-214628-MS. www.doi.org/10.2118/214628-MS

Ali, S.A., Luyster, M.R., and Patel, A.D. 2006. "Dual Purpose Reversible Reservoir Drill-In Fluid Provides the Perfect Solution for Drilling and Completion Efficiency of a Reservoir." SPE/IADC Indian Drilling Technology Conference, Mumbai, India, October 16-18, 2006. SPE-104110-MS. www.doi.org/10.2118/104110-MS

Battistel, E., Bianchi, D., Fornaroli, M., Guglielmetti, G., Europa, P., and S. Cobianco. 2005. "Enzyme Breakers for Chemically Modified Starches." SPE European Formation Damage Conference, Sheveningen, The Netherlands, May 25-27, 2005. www.doi.org/10.2118/94702-MS

Bennett, N. 1988. "Use of Graded Salt Pills in the Montrose Field." European Petroleum Conference, London, October 16-19, 1988. SPE-18384-MS. www.doi.org/10.2118/18384-MS

Carpenter, C. 2024. "Enzyme-Based Cleanup Fluid Effective for High-Temperature Filter-Cake Removal." *Journal of Petroleum*

Technology, vol. 76, no 3 (March 2024) 83–85. SPE-0324-0083-JPT. www.doi.org/10.2118/0324-0083-JPT

Derkach, E., Hayden, S., Tresco, K., Escobar, L. and Luyster, M. 2020. “Laboratory Evaluation of Peroxides for Degrading Polyacrylamide as Used in Fracturing Suspensions and Solids-Free Systems.” AADE-20-FTCE-114. Available from www.AADE.org

Dobson, J.W. and Kayga, P.D. 1993. “Soluble Bridging Particle Drilling System Generates Successful Completions in Unconsolidated Sand Reservoirs.” 5th International Conference on Horizontal Well Technology, Amsterdam, The Netherlands, July 14-16, 1993.

Dobson, J.B, Jr., Kayga, P.D., and Fagan, M.R. 1995 “Unique Breaker System Treatment for Open Hole Horizontal Completions.” 7th International Conference on Horizontal Well and Emerging Technologies, Houston, Texas, November 6-8, 1995.

Fonseca, S.H., Torres, R., Liu, Z., Jahn, F., Tagarot, G., Baca, S., Guevara, H., Botan, J., Villacres, C. Boas, J. 2023. “Challenges and Practices for Recovering Stuck Coiled Tubing Pipe.”. *SPE Production & Operations,* vol. 38, no. 4 (November 2023) 651–665. SPE-215819-PA. www.doi.org/10.2118/215819-PA

Hassan, M., Nour, A., Al-Yaqout, T., Agarwal, C., Al-Mejmed, S., Al-Saleh, F., Al-Shammari, Y., Al-Hazeem, F., Al-Khatrash, M., Safar, E., and Hassan, A. 2018. “Innovative Solution for Fluid Loss in Sub-Hydrostatic Wells During Workover Operation – Case Study from Kuwait.” SPE Russian Petroleum Technology Conference, Moscow, Russia, October 15-17, 2018. SPE-191528-18RPTC-MS. www.doi.org/10.2118/191528-18RPTC-MS

Hussein, M., Al-Rashedi, H., Al-Naqi, A., Gonzalez, S., Erhamah, A., Najaf, R., Malik, S., Bosilca, D., Ali, M., Tresco, K., and Luyster, M. 2022. “Improving Fluid Loss Control During Well Intervention: A Case Study on the Use of Innovative Salt System.” SPE International Conference on Formation Damage Control, Lafayette, Louisiana, February 23-24, 2022. SPE-208833-MS. www.doi.org/10.2118/208833-MS

Mahajan, N.C. and Barron, B.M. 1980. “Bridging Particle Size Distribution: A Key Factor in the Designing of Non-Damaging Completion Fluids.” SPE Formation Damage Symposium, Bakersfield, California, January 28-29, 1980. SPE-8792-MS. www.doi.org/10.2118/8792-MS

Mondshine, T.C. 1977. “Completion Fluid Uses Salt for Bridging, Weighing.” *Oil & Gas Journal* (August 22, 1977) 124-128.

Mondshine, T. 1981. “Crystalline Salt Systems Proving Valuable in Drilling-Completing.” *Oil & Gas Journal*, vol. 79, no. 3 (1981) 79-82.

Mondshine, T.C. 1986. “Water Soluble Perforation Pack.” US Patent 4,621,692 (Nov 11, 1986). https://ppubs.uspto.gov/dirsearch-public/print/downloadPdf/4621692

Mondshine, T.C. 1989. “New Polymer Improves Water-Soluble Completion Fluids.” *Petroleum Engineer International* (February 1989).

Reddig, L.W. 1970. “Current Drilling Practices, Gomez Field, Pecos County, Texas.” SPE Deep Drilling and Production Symposium, Monahans, Texas, March 1970. SPE-2856-MS. www.doi.org/10.2118/2856-MS

Repiotraschke. No date. Evaporite Precipitation Sequence Diagram www.quizlet.com/311596042/evaporite-precipitation-sequence-diagram/

Ruppel, S. 2019. "The Fusselman of the Permian Basin: Patterns in Depositional and Diagenetic Facies Development On A Stable Platform During the Late Ordovician-Early Silurian Icehouse," University of Texas at Austin, Bureau of Economic Geology. *Anatomy of a Paleozoic Basin: The Permian Basin, USA,* vol. 1, 379-399. www.beg.utexas.edu/resprog/permianbasin/geolog_synth/members/PBGSP_members/writ_synth/Fusselman.pdf

Sinomine Specialty Fluids. 2022 “Formate Technical Manual.”

Sneeden, J.W. and Galloway, W.E. 2019. The Gulf of Mexico Sedimentary Basin: Depositional Evolution and Petroleum Applications; Cambridge University Press (2019) p.248-291. www.doi.org/10.1017/9781108292795.014

Stagg, T.O., Powell, J.W., Dewees, R.L. and Stephens, M.P. 1986. “Horizontal Drill-In Project Uses Sized Salt Fluid.” *Petroleum Engineer International* (July 1986) 31-36.

Thompson, S. 2023 “Crystals That Dissolve in Water: Properties, Factors, Uses, and Environmental Impact.” InnerHunches. www.innerhunches.com/crystals-that-dissolve-in-water

Wright, W.F. 1979. *Petroleum Geology of the Permian Basin*; West Texas Geological Society, Publication No. 79-71.