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Designing and Managing Screen Running Fluids (SRF)

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Abstract

Formation damage costs operators millions of dollars annually in reduced production and/or injection relative to original predictions made before beginning a drilling campaign. This "hidden cost" can be attributed to many factors during the drilling and completion phases. Several elements should be considered when designing a fluid for a specific reservoir, including the following:

- Shale inhibition.
- Fluid Compatibility
- Bridging across the reservoir.
- Completion design compatibility.

This last point, completion design compatibility, is a critical element regarding successful running of optimally designed completions to maximize returns from the reservoir. Standalone screens (SAS) are susceptible to plugging by particles contained within the fluid; a gauge hole is drilled and maintained to help ensure that screens can be run to the desired total depth. To understand how the fluid choice impacts the completion operation, one would need to understand what impact the fluid has on the following steps of the three completion types, see Figure 1.

- Lower completion.
- Cased and perforated completions.
- Upper completion.

Low-solids screen running fluid (SRF) provide benefits through:

- Quicker casing cleanout due to lesser swab/surge margins (high concentration of solids in the fluid can lead to excessive surge/swab pressure) and less fluid conditioning.
- Reduced risk of middle completion installation problems due to minimum solids and debris on top of the pre-installed barrier.
- Less time to displace to completion brine since the well is already filled with a low-solids fluid.

This paper discusses the design and field management of completion specific SRFs that prevents completion and formation damage and facilitates a simpler and more economical completion, which reduces costs and improves performance.

Introduction

Overview of Openhole Stand-Alone Screen Completions

Oil and gas reservoirs exist in all types of sand, but formation sand particles in a well stream can hinder production, causing major problems with flowlines and surface production equipment. Several factors, such as the strength of the reservoir, its lithification and cementation and reduction in pore pressure, may cause sand to be separated from the rock and transported by hydrocarbons to the well. Producing sand commonly causes erosion and corrosion of downhole and surface equipment, leading to production interruptions and sometimes forces operators to shut-in wells. Effective sand control is crucial to helping maximize production from unconsolidated formations while enhancing wellbore stability. Screen systems deliver the full spectrum of screening solutions to support sand control needs, see Figure 2. *Ahad, N.A. et al, 2019*

Knowledge of reservoir sand properties—such as particle size, particle size distribution (PSD) and particle size uniformity-is central to the design of sand-control completions. The choice of well screen, based on the reservoir PSD and other considerations, can have a far-reaching effect on the productivity and efficiency of a producing well. *Mahmud, et al, 2020*

- Sizing that is too small can lead to total or partial plugging, forcing hydrocarbon production through non-plugged sections. This situation causes what is known as "hot spotting," which can lead to screen erosion.
- Sizing that is too large can lead to unacceptable production of sand, which in turn can lead to erosion of sand screens and surface equipment. Excessive sand production rates can result in loss of the well.

Screen selection involves a multidisciplinary, integrated approach that combines reservoir engineering, completion design, wellbore preparation, and filtercake removal. *Farrow, C. et al, 2004*

- Prevent plugging and erosion to protect your wellbore and downhole well architecture with wire mesh screens engineered for resistance in any downhole environment.
- Maximize your reservoir conductivity. Whether the payzone requires fracturing, stimulation, artificial lift, or gravel packing, screens offer unsurpassed mechanical strength and sand-free production from the reservoir to the wellhead.

- Enhance long-term production by installing screening systems at the payzone to confidently deliver completion fluids, proppants, and other stimulation technologies while ensuring maximum sand exclusion to delay gas or water coning.

Overview of Formation-Completion Damage

Formation damage studies require a cooperative effort between various professionals to combat the formation damage problems that includes understanding relevant processes by laboratory and field testing; optimizing for prevention and/or reduction of the damage potential of the reservoir formation; and developing methodologies and optimal strategies for formation damage control and remediation. *Civan, 2015*.

Formation-Completion damage is, as the name implies, the combined damaging impact the SRF may have on the completion and formation if designed incorrectly. The principal causal factor is attributed to fluid stability during extended static periods at bottomhole pressure and temperature. Ideally the fluid should remain as one phase and fully mobile for the required duration of well suspension (temporary well abandonment). *Fleming, N. et al, 2022*

Any separation or syneresis of the fluid will tend to typically result in a less dense, more mobile phase overlaying a denser, less mobile to completely immobile phase. Any solids in the fluid – bridging solids, filtration agents, clays or similar viscosifiers – will tend to be incorporated in the lower, denser phase. Separation of the fluid can result in loss of wellbore hydrostatic overbalance, i.e., this is particularly true for horizontal wells. *Fleming, N. et al, 2022*

Loss of overbalance can promote crossflow between the near-wellbore reservoir and the wellbore potentially causing chemical or mechanical formation damage. The denser, less mobile, or even immobile phase of the fluid can damage the completion in the form of plugging and flow impairment. In an extreme case an immobile fluid mass can block over 50% of the inflow area of the completion substantially reducing production, see Figure 3.

Criteria for Successful Back Production through Sand Control Screens

Sand control screens are designed to retain formation sand. To do this, sand control screens have slots narrower than the largest sand grains and as a result, the screen slots are only slightly wider than the reservoir rock's largest pores. For this reason, any operation where the drilling fluid plugs the formation sand's largest pores without also plugging the sand screen slots requires meticulous planning and control of both the drilling fluid and the screen slot width. *Marken, C.D. et al, 1998.*

To safely execute such operations, the team must thoroughly understand the plugging mechanisms. The team should be able to predict the screen slot width needed to prevent plugging by a fluid containing particles of a given concentration and PSD. Additionally, it is useful to estimate the volume of drilling fluid that can pass through the sand control screen before plugging occurs. *Marken, C.D. et al, 1998*

When the sand control screen and drilling fluid have been chosen, the size and concentration of drill cuttings in the drilling fluid must be carefully controlled when drilling through the reservoir. The size of the solids can be controlled most easily during drilling by changing the screen in the shale shakers. For this reason, it is very important to know what size of openings in the shale shaker screens are required to avoid plugging of a certain sand control screen. The plugging of sand control screens by drilling fluids is important for at least two reasons:

- If the sand control screen is plugged completely or partially with drilling fluid, the productivity of the well is reduced, and costly operations involving clean-up fluids and filtercake breakers may be required.
- If the sand control screen is partially plugged by drilling fluid, the local velocity through the screen slots may become high enough to cause erosion of the screens and uncontrolled sand production. No available data is published quantitatively describing the erosion of sand control screens; preliminary results from ongoing work suggest that differential pressures of more that 14-28 psi (1-2 bar) across a partially plugged screen may cause an unacceptably high erosion rate. *Procyk, A. et al, 2015.*

General Plugging Theory for Sand Control Screens

Drilling fluids are designed to block the surface of the pores in the reservoir rocks without particle invasion into the pores. For a specific drilling fluid with a certain PSD, stable arches will be formed and cause immediate plugging of narrow slots in the initial stages. Then the openings in the arches are filled and stabilized by smaller particles, clays, polymers, emulsions, or any other material present in the drilling fluid. Afterwards, when the slot width increases, unstable arches resulting in partial plugging are experienced until the slots are too wide for arches to form at all and no plugging is observed. *Marken, C.D. et al, 1998*

For prepacked screens the situation is slightly different, they experience plugging not only by a filtercake that forms on the screen surface, but also by particles that invade the layer of prepacked gravel and is trapped inside. Thus, it should be expected that pre-packed screens will be plugged more easily than single wrapped screens, and that the plugging will be more permanent. *Ma, C. et al, 2021*

The plugging of sand screens by drilling fluids is difficult to predict. The broad range of particle size makes it difficult to model the bridging across the slots. Therefore, a single measurement of plugging can appear to be a random process, reason why, a series of measurements is preferred to show definite trends. Fresh drilling fluid, i.e., drilling fluid that has not been conditioned over the shale shaker screens, is much more likely to plug sand control screens that conditioned drilling fluid. This contrasts with the common idea that a well should be filled with new drilling fluid before running sand control screens. Such freshly mixed drilling fluids cannot normally be conditioned over fine mesh shaker screen without an unacceptably density decrease. *Mathisen, A.M. et al, 2007*

The plugging of sand control screens by drilling fluids depends on many factors, including the type and geometry of the screen, the type and rheology of the drilling fluid, the velocity and solids concentration of the drilling fluid, and the particle size distribution of the drilled solids. *Marken, C.D. et al, 1998*

Screen Running Fluids Design

Types of Screen Running Fluids

Typically, SRFs are divided in the following four categories:

- Clear Brine Fluids.
- Water-based solids-ladened SRFs – includes screened water-based reservoir drill-in fluid (RDF).
- Non-aqueous-based (NAF) solids-free SRFs.
- NAF solids-ladened SRFs – includes screened NAF RDF.

Water-Based Screen Running Fluids

Water-based SRFs are designed to be:

- Compatible with RDF, either water-based or NAF.
- Low solids systems that rely upon clear brine to achieve the required density to match the specific wellbore requirements, see Table 1.
- 5 to 20 lb/bbl (15 to 57 kg/m^3) of properly sized bridging particles.
  - In some cases, if high losses are expected, higher concentrations can be formulated. Formulations that differ from this recommendation should be verified by the Fluid Engineering Team.
- Bridging PSD primarily engineered to avoid screen plugging and repair RDF filtercake damage during screen installation.
- Low concentration of solids improves the mobility of the fluid after suspension around the lower completion.
- Reduced disruption to production facilities versus fluids with higher solids loading and surfactant concentration.

Non-Aqueous Based Screen Running Fluids

NAF SRFs are designed to be:

- Compatible with RDF; NAF.
- Low solids systems that rely upon the oil-water-ratio (OWR) and internal brine to achieve the required density to match the specific wellbore requirements in addition to:
  - Reduce risk of screen plugging during screen running.
  - Reduce risk of screen plugging or immobility after suspension around the lower completion.
  - Reduce consequence of settling.
  - Reduce disruption to production facilities versus fluids with higher solids loading.
  - Fully compatible with NAF RDF.
- A low OWR ratio of typically 40/60 – 60/40.
- 5 to 20 lb/bbl (15 to 57 kg/m^3) of properly sized bridging particles.
  - In some cases, if high losses are expected, higher concentrations can be formulated. Formulations that differ from this recommendation should be verified by the Fluid Engineering Team.
- Bridging PSD primarily engineered to avoid screen plugging and repair RDF filtercake damage during screen installation.
- Low concentration of solids improves the mobility of the fluid after suspension around the lower completion.
- Disruption to production facilities is a risk due to surfactant content.

Baker Hughes Solids-free Non-Aqueous Fluid System

Baker Hughes' NAF SF a solids-free synthetic-based NAF SRF system for use in demanding downhole environments influenced by elevated temperatures and ambitious drilling and completion objectives. The system can be formulated with calcium chloride ($CaCl_2$), calcium bromide ($CaBr_2$) and the high-density, non-zinc, solids- free completion fluid (HDNZ), as the internal phase, providing the necessary requirements for density.

Technical requirements:

- 5 days sag factor 0.50 – 0.53.
- Flat Rheology profile across 40 to 150°F.
- Stable up to 300ºF and 12.8 pound per gallon (lb/gal).
- Stable at OWR as low as 40:60.

The system allows optimal and constant rheological properties, superior lubricity, tolerance of LGS and requires minimum treatment.

Selection Criteria for Screen Running Fluids

A decision matrix, see Table 3, can be used to help qualify the selection process, and moreover, used in discussions with the customer to inform, rank and conclude the design process. The decision matrix should reflect viable options for SRF relative to operational and production requirements, e.g., well control, formation damage, fluid compatibility, displacement procedures, well suspension and clean-up procedures, section cost and operational time.

Although SRFs are designed to be compatible with the screens, verification via production screen test (PST) is necessary, testing MUST be performed on the fluid prior to be pumped into well and on returns from well upstream shakers in the case of full well displacements. For screened RDFs:

- The fluid used to drill the reservoir can be filtered through properly sized shaker screens to run the sand control screens in the filtered fluid. This option is only applicable after thoroughly assessing potential formation and completion damage, as well as evaluating operational progress and logistics.

- Shaker screens size to retain particles larger than 40% of the screen aperture size (slot opening/filer size).

Qualification Testing for Screen Running Fluids

Laboratory testing to qualify and verify fluids at the relevant field conditions should be performed as suggested in this section. Laboratory testing can be valid for multiple well applications using similar fluids under similar conditions. Standard test methods should be performed as a minimum, non-standard testing should be evaluated based upon field/well specific challenges. A plan for testing including timeline and test methods should be agreed with the operator.

To design and qualify a SRF, the following tests are required.

Compatibility with Reservoir Formation and Formation fluids, and Reservoir Drill-In Fluids

Among the many factors to consider when choosing a drilling fluid, drill-in and SRFs are the well's design, anticipated formation pressures and rock mechanics, formation chemistry, the need to limit damage to the producing formation, temperature, environmental regulations, logistics and economics. Specific requirements for SRFs are derived from the specific customer needs. The typical flow of design and testing include and is not limited to, see Figure 4.

In most cases the SRF is chemically closely related to the drill-in fluid whether it is a water-based or a NAF system. This means, any formation damage testing completed to qualify the RDF is applicable to the SRF, therefore, to meet the design factors:

- Confirm reservoir drilling data – what RDF system was used and with what results. Proceed to:
  - Select the base brines for the system based on density and True Crystallization Temperature (TCT).
  - Select the base-oil for NAF SRFs to match the requirements of kinematic viscosity and emulsion tendencies.
- Examine the reservoir mineralogy to dictate the use of a specific brine type vs NAF SRF. Reactive shale typically warrants NAF-SRF.
  - While the fluid phase of a NAF and a water-based SRF perform similar functions, they have differing effects on the reservoir (rock and native fluids) and require different products to formulate functioning fluids..
- Examine the fluid-fluid compatibility, i.e., formation fluids and base brines and/or base oils. Incompatible fluids can cause formation damage that may be irreversible.
- If solids are required in the formulation, the screen gauge will determine the proper bridging package necessary to restore the thin, easily removable filtercake without plugging the screens.
- Optimize fluids rheological properties and use same to model the displacement hydraulics.
- Assess filtercake clean-up with breaker.
- Perform return permeability testing (when required).

Specific testing for SRFs are detailed in the sections below.

Screen Running Fluid – Fluid Loss Control

SRFs must be able to repair the damaged caused to the existing filtercake at high-pressure/high-temperature filtration conditions. Testing is performed using the permeability-plugging apparatus (PPA).

Test Steps

1. Filtercake deposited on filter disk using RDF using the PPA.
2. Carefully disassemble PPA and remove aloxite disk.
3. To replicate damage to the RDF filtercake, two options are available.
   a. Carefully scrape away half of the filtercake, as shown in Figure 5.
   b. Carefully scrape a groove of fixed width through the center of the filtercake, as shown in Figure 6.
4. Replace disk in PPA and reassemble.
5. Repeat fluid loss test using the SRF and measure spurt loss and fluid loss.
   a. Non-Standard test.

Compatibility with Sand Control Completion

The flow-back characteristics of SRFs are critical to the productivity of a well. If the fluid plugs the production screen, it will not only slow down production, but it could also lead to screen erosion and costly remediation. Screens used for sand control (SAS/Gravel Pack/Frac Pack) are sensitive to plugging during installation and must be run in a compatible fluid. To avoid screens being plugged during and after installation, all fluids that the screens will be exposed are to be tested for suitability by production screen testing using a Production Screen Tester (PST).

The PST allows to run flow-back tests right at the rigsite with samples of the actual production screen being used downhole. The test is similar to the standard American Petroleum Institute (API) filter press. The test will quickly show whether the screen and SRF are compatible.

Test Highlights. Prior to installing the screen coupon check to confirm correct mesh size screen coupon provided.

- Inspect the screen visually for evidence of plugging and record any findings.
  - A digital photo shall be taken on the coupons and submitted in the end-of-well-report (EOWR).
  - Test Screen Diameter is 48mm; dependent on equipment.
  - Test pressure is 10-psi.
  - Flow 4 liters in 1000mL batches. A minimum of 4 liters is recommended. Follow customer specific requirements.
- Set a timer, open the bottom valve, and time the drilling fluid flow from the bottom of the cell. Note the time taken at every 1000mL.

- Refill cell after each 1000mL.

One screen coupon can be used only for one test; weave screen coupons cannot be re-used even after successful tests as if any plugging occurs, as it would be permanent, and coupons cannot be further cleaned efficiently. Wire-wrap screen coupons can typically be reused if properly cleaned after each test. The best cleaning method is to first wash the coupons, then carefully but thoroughly clean each slit with a wire-wrap gauge testing tool matched to the screen size. After cleaning, no particles should be visible when looking through the screen. However, it is recommended to have enough spare coupons to avoid reuse. Coupons should not be reused if the gauge size has changed during testing or cleaning.

Test acceptance must be verified by the Completions Supervisor and Wellsite Leader. All the PST data must be reported using the PST Results Report. Pictures of the coupons must be taken and reported as well. All the PST data must be reported. See Figure 7.

- PST PASS. SRF takes equal amounts of time for each 1000 mL sample to flow through the screen coupon.
- PST FAIL. SRF takes increasing amounts of time for each 1000 mL to flow through the screen coupon. SRF decreases to a drip; note the drilling fluid volume that has passed through the screen

Time Dependent Fluid Stability: Mobility

SRFs must be stable under bottomhole conditions of pressure and temperature conditions.

Mobility Test Highlights. SRF should be mobile and be produced out of the well with minimal drawdown. Mobility of fluid to pouring from ageing cells or glass bottles; adherence to container and residual material is characterized. Testing is performed in parallel with static sag testing, as follows:

1. Pour the last 100mL that is left in the aging cell into a beaker.
2. If the fluid is easy to pour and have an even flow the fluid is mobile. The drilling fluid is immobile if it has to be digged out the fluid from the cell.
3. Vials were photographed immediately after, see Table 4 and Table 5.

Time Dependent Fluid Stability: Specialized Fluid Mobility and Clean-Up Test

SRF is placed in a simulated wellbore with sand control completion and static aged at reservoir temperature and pressure. At end of ageing period, the SRF is displaced by oil to simulate well production, see Table 6.

Time Dependent Fluid Stability: Syneresis

SRFs must be stable under bottomhole conditions of pressure and temperature conditions.

Syneresis Test Highlights. SRF should be stable at reservoir temperature in the period from being pumped into the well until clean up production and remain as homogenous as possible, with no settling of bridging (and weighting) materials. Syneresis test allows for an understanding on limitations regarding the fluid ability to perform as required, see Table 7.

Field Best Practices for Screen Running Fluids - PST Fluid Conditioning Fundamentals

Ensuring the fluid in the well prior to screen completions are conditioned and pass the PST and other related criteria is of utmost importance; poorly conditioned fluid can cause screen plugging, reducing screen permeability, and increasing skin factor ultimately impairing the productivity of the well. Key risks and mitigations need to be reviewed to ensure the fluid is conditioned to PST specification in an efficient manner.

Insufficient hole cleaning at Total Depth (TD)

Poor hole cleaning can result in additional time needed to reach a successful PST test due to incorporation of cuttings into the system. When cleaning the hole, sufficient annular velocity, rotation, and circulation time should be employed to ensure the hole has been cleaned. These requirements should be designed and selected based on the well design.

For hole cleaning prior to PST conditioning, the annular velocity should be >200 ft/min and string rotation >120 revolutions-per-minute (RPM), for deviated wells, maximum achievable flowrate should be used.

Damage and erosion to the wellbore

Once the hole has been cleaned at TD, a wiper trip should be performed to simulate running the completion screens. Once the trip back to TD has been completed and to ensure any solids from the wellbore have been removed, the well should be circulated. For this circulation, a lower rotation (60-80 RPM) will assist with the removal of solids while reducing further damage to the wellbore and the risk of solids incorporation. Annular velocity should be 200 ft/min.

When conditioning the openhole, the possibility that the fluid does not reach an accepted PST criteria due to material continuing to fall into the well exists. In this case a maximum of 4 Full circulating system volumes (FCSV) should be followed.

Full Circulating System Volume (FCSV) = Total volume of fluid being circulated in the well (i.e., FCSV = Active & Return Pit Volumes + Line Volume + Drill Pipe Volume + Annular Volume)

If the fluid is still not passing the accepted PST criteria, a wellbore clean-up bottomhole assembly (BHA) should be pulled back inside the casing shoe. Once inside casing shoe, circulation and PST testing will recommence until the required conditioning criteria are met. It is recommended that the openhole is displaced to a solids-free SRF to reduce the time required to condition the active system.

Surface Clean-up

If the surface lines are not cleaned or have been poorly cleaned before operations commence, the solids in the flowline will be incorporated into the active system increasing the time it takes to achieve a successful PST test.

Thorough cleaning must be performed prior to start fluid conditioning. Rig equipment and lines that encounter the flowline, possum bellies, shale shaker boxes and sand traps, should be cleaned of any accumulated drilled cuttings. Solids residue from the active pits where the conditioned fluid will be circulated should also be cleaned. Sand traps and trip tanks should be emptied of non-conditioned fluids and cleaned of solids prior to adding conditioned fluid. A cleaning plan should be prepared by the Fluids Engineer and reviewed by the rig personnel to ensure all required equipment is cleaned of solids.

Shale Shaker Screens

Damaged shale shaker screens and/or poor screen size selection could result in the retention of solids into the fluid potentially leading to the inability of achieving a successful PST test. Additional efforts should be made to employ the allowable finest shale shaker screens while drilling the reservoir section while circulating at the normal drilling flowrate, without impacting the PSD. Screen size should be selected based on the completion screen that is being utilized. This should be confirmed by the operator or the completions provider. Below are typical values for the sand control screens:

- Fine: 100 to 200 D_{10} micron range.
- Medium: 200 to 300 D_{10} micron range.
- Coarse: >300 D_{10} micron range.

** D_{10} equals the dimension of the grain size at the largest 10th percentile ($D_{10} > D_{50}$)*

For conditioning to PST specifications, the initial shale shaker screen selection, and the speed of fining up to the required screen size will be determined at the rigsite based on the following criteria:

- The shale shaker screen sizes used at end of drilling phase should be the minimum starting point for conditioning the fluid.
- The observed performance of the shale shaker screens during the fluid conditioning operation, e.g., the ability of the screens to sustain high flowrates without blinding and wearing out.
- API 270/325 screens will result in a lower achievable flowrate.

Regular checks of the shale shaker screens must be performed to ensure that no holes are present; even a small number of small holes will lead to an inefficient conditioning process. If the PST test from the active pit is not improving and there appears to be little improvement in fluid cleanliness, it is likely that there are holes in the shale shaker screens.

Losses Contingency

During the planning phase, the risk of downhole losses should be reviewed to understand the additional volume needed. Any conditioning on the fluids should be done offline where possible or during the well fluids conditioning stage.

Field Testing Criteria

During the planning phase the volume of the sample to be tested should be confirmed with the operator. PST procedure and screen coupons cut from the screen type and size of the completion should be used.

An initial test should be done at TD to determine the condition of the fluid before commencing the screening process. Samples from the return line downstream of the shale shakers can be tested once fine mesh screens have been change over to confirm that the shale shakers screen sizes are correct for the screen completion operation. If these samples pass the test, then sampling can begin from the header box. Once testing from the header box begins samples of fluid should be taken at the following times to be tested:

- When circulation over fine mesh shale shaker screen commences (to establish a baseline).
- After the first FCSV have completed.
- Every bottoms-up thereafter until circulation is complete.

On each occasion, fluid samples should be taken from 2 locations:

- The return flowline / header box upstream of the shaker screens - to understand fluid quality coming out of the well.
- The active pit - to ensure that fluid quality entering the well has not deteriorated since passing over the shale shakers e.g., holes in the shaker screens.

After 3 successful PST tests from the header box testing needs to be repeated with samples from the active system. This confirms that fluid exiting and entering the well are in PST specification. It is recommended to run one more test on the fluid from the active system to make sure that active pit is also in PST specification before stopping.

Handling Conditioned Fluids

Once the fluid has passed the PST test, no more fluid treatments with solids or polymers should be performed. If any weighted pills or slugs are to be pumped, they should be PST-checked and screened through fine shaker screens if necessary. No weighted pills or slugs can be introduced into the well without passing the PST test.

Any solids-free / low-solids completion fluids should undergo a PST test to ensure no solids have been picked up in transit or during transfer.

Field Fluid Conditioning Guidelines

Fluid volumes should be reviewed to identify the available options for displacing and conditioning to PST specifications. The below options are dictated based on the ability to condition fluids offline, the available reserve volume, well volume, and operations that will allow circulating over the shale shakers without impacting well monitoring, e.g., tripping.

In both the below scenarios rotation and reciprocation of the string in the openhole should be avoided as this can prolong the conditioning time due to hole erosion.

- Fluid conditioning of the well can result in the reduction of the fluid density as solids are removed from the fluid. This reduction needs to be considered before fluid conditioning to ensure additional bridging material is available to maintain the fluid density.

The sand traps should be by-passed whilst the entire active system is circulated over the shale shakers. It is recommended that during the clean-up phase, returns are diverted into a previously cleaned pit and subsequently draw fluid from this pit to minimize problems observed with settled solids at the bottom of the pit.

Condition of Entire Well Volume

Conditioning the entire well volume is typically performed when there is no opportunity to condition the fluid offline and there is not enough reserve fluid or pit space to condition additional volume.

Conditioning can be done when TD is reached; the most efficient option is to condition the fluid inside the casing then run back to TD to displace the openhole volume with conditioned fluid in the active system. The fluids from the openhole will have to be conditioned once back into the casing.

Displace Entire Well Volume

When it is possible to displace the entire well volume this would be the preferred option. This requires enough volume on surface to displace the well and offline time to condition the reserve fluids. All surface lines should be cleaned of solids before the displacement. Partial well displacement can be done where there is limited space and reserve volume. A partial displacement will allow the displacement of the openhole and some of the casing without performing a second conditioning of the casing volume. Ensuring the openhole can be displaced will reduce the time to condition the well.

Conclusions

The correct design and maintenance of a SRF is critical where openhole completions are planned. The particle-size distribution of solids in the openhole must be carefully chosen, primarily to bridge across the exposed formation, but it may also permit flowback through the openings in the completion assembly.

Thorough laboratory testing is vital in the engineering design of SRFs but once drilling has started, field monitoring of particle size distribution and flow-through characteristics of SRF is critical for successful openhole completion operations.

Optimal fluid displacement plans regarding to completion screen size and rig limitations play a key part in field deployment of SRFs to ensure conditioned fluid prevent screen plugging and improves operational performance.

Acknowledgments

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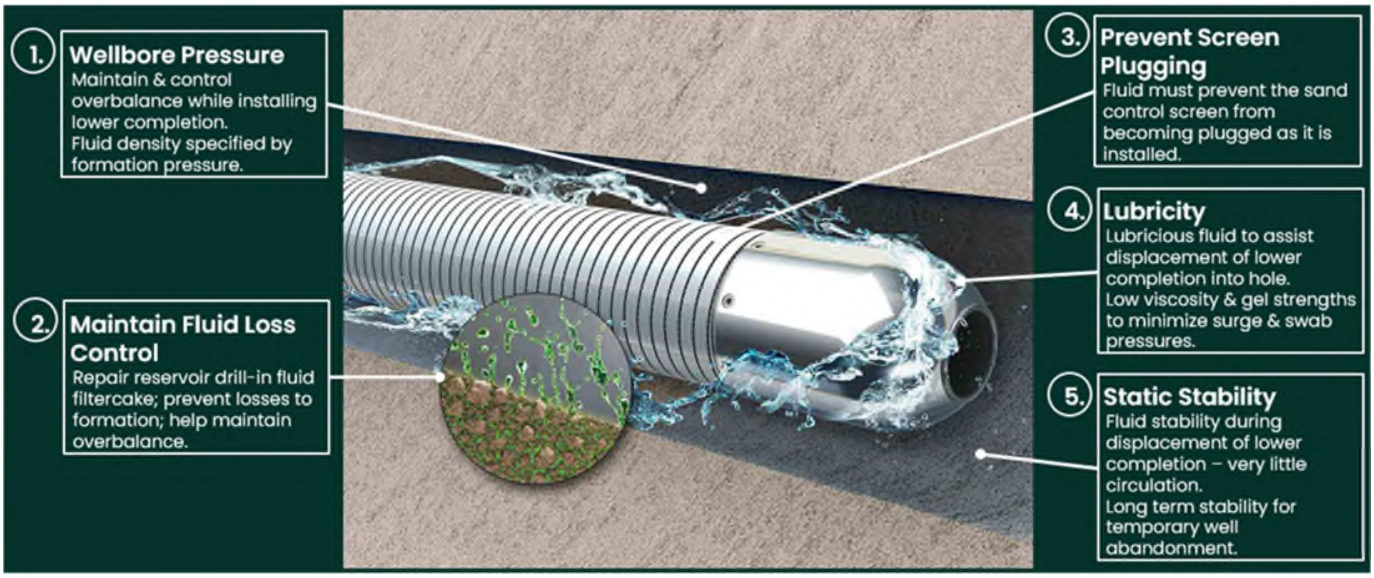


Figure 1. Why is a SRF used?

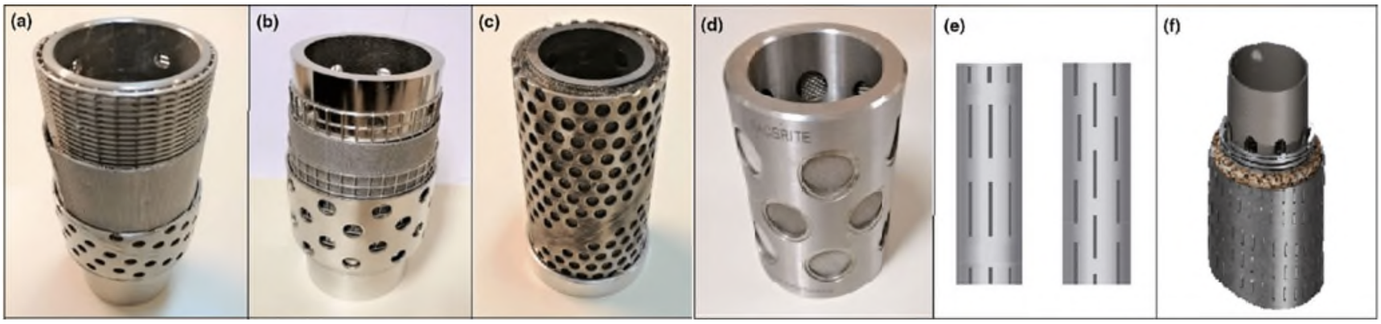


Figure 2: Different types of SAS (a) and (b) premium screens with multiple layers; (c) wire-wrapped screen; (d) basic screen; (e) slotted liner; and (f) prepacked screen. ***Ahad, N.A. et al 2019***

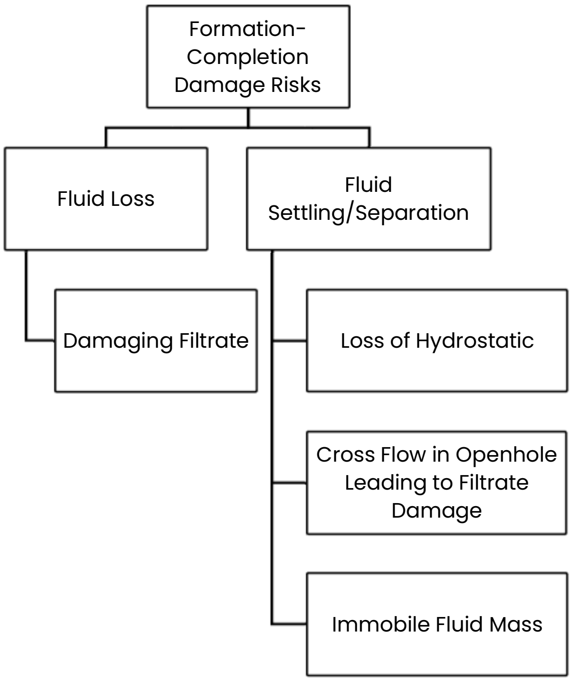


Figure 3: Classification and order of typical formation-completion damage mechanisms

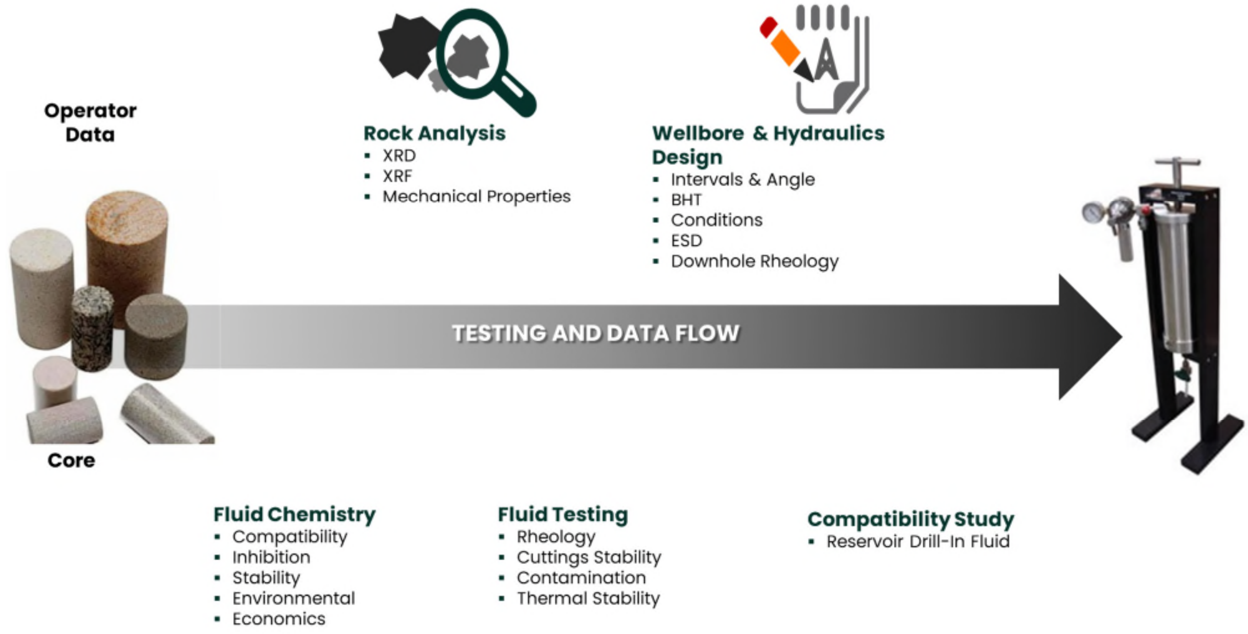


Figure 4: Systematic Approach to Design & Selection of SRF

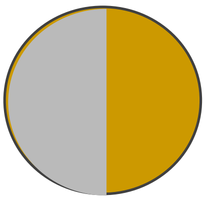


Figure 5: Scraped Filtercake from aloxite disk

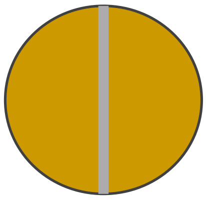


Figure 6: Scraped Filtercake from aloxite disk

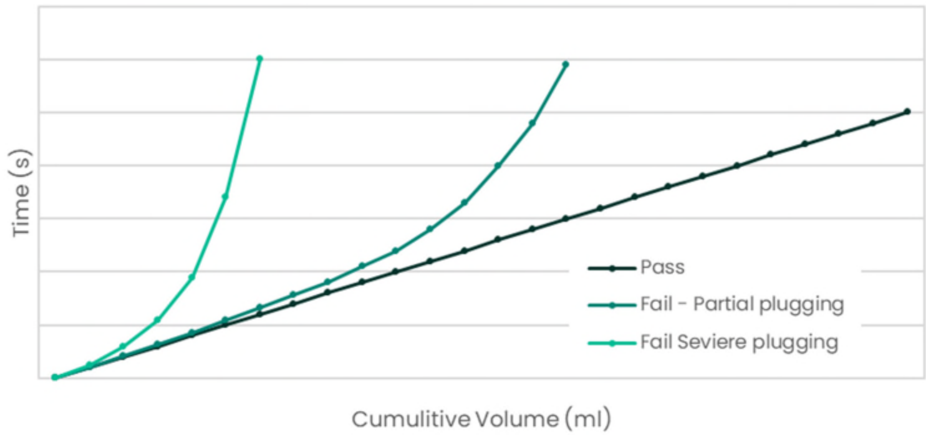


Figure 7: Sample PST Results

Table 1: Commercially available clear brine fluids

Monovalent Brines		Commercial Density 68 °F (20 °C)
Potassium chloride	KCl	9.68 lb/gal (1.163 SG)
Sodium chloride	NaCl	10.01 lb/gal (1.20 SG)
Sodium bromide	NaBr	12.72 lb/gal (1.53 SG)
Mixed Salt	NaCl/NaBr	12.72 lb/gal (1. 53 SG)
Divalent Brines		**Commercial Density 68 °F (20 °C)**
Calcium chloride	$CaCl_2$	11.64 lb/gal (1.39 SG)
Calcium bromide	$CaBr_2$	14.27 lb/gal (1.71 SG)
Zinc bromide	$ZnBr_2$	19.2 lb/gal (2.30 SG)
Mixed Salt	$CaCl_2/CaBr_2$	14.52 lb/gal (1.74 SG)
Mixed Salt	$CaCl_2/CaBr_2/ZnBr_2$ or $CaBr_2/ZnBr_2$	19.2 lb/gal (2.30 SG)
Formate Brines		**Commercial Density 68 °F (20 °C)**
Sodium formate	NaCOOH	11.05 lb/gal (1.32 SG)
Potassium formate	KCOOH	13.10 lb/gal (1.57 SG)
Cesium formate	CsCOOH	19.19 lb/gal (2.30 SG)
Mixed Salt	NaCOOH/KCOOH	13.10 lb/gal (1.57 SG)
Mixed Salt	KCOOH/CsCOOH	18.36 lb/gal (2.20 SG)
High-density, Non-zinc, Solids- free completion fluid (HDNZ)		**Commercial Density 68 °F (20 °C)**
Monovalent	HDM and XHDM	15.5 lb/gal (1.86 SG)
Divalent	Gen 1, HDD and XHDD	17.5 lb/gal (2.10SG)

Table 2: Baker Hughes' NAF SF density range

Density Range	Internal Brine Type
< 10 lb/gal (1.20 SG)	$CaCl_2$
10 – 11.7 lb/gal (1.20 - 1.40 SG)	$CaBr_2$
11.7-12.8 lb/gal (1.40 - 1.53 SG)	HDNZ

Table 3: Decision matrix for selecting SRFs

	Clear Brine	WB solids-ladened SRF	NAF solids-free SRF	NAF solids-ladened SRF
Well Control: Pressure	Provides Hydrostatic.	Provides Hydrostatic.	Provides Hydrostatic.	Provides Hydrostatic.
Well Control: Flow	No Fluid loss control.	Restores Filtercake	No Fluid loss control	Restores Filtercake
Displacement procedure: Drill-in to SRF	If WB DIF, direct displacement. If NAF DIF, Indirect displacement.	If WB DIF, direct displacement. If NAF DIF, Indirect displacement.	If WB DIF, not selected. If NAF DIF, direct displacement.	If WB DIF, not selected. If NAF DIF, direct displacement.
Fluid Syneresis	No fluid separation.	Polymer degradation with temperature & time.	Emulsion destabilization with temperature & time.	Emulsion destabilization with temperature & time

		Potential for solids settling.		Potential for solids settling.
Fluid Mobility	Mobile.	Potential for immobile mass.	Mobile.	Potential for immobile mass.
Total Fluid Cost	Dependent on brine type & density.	Dependent on brine type, density & product additions.	Dependent on brine type & density, & product additions.	Dependent on brine type, fluid density & product additions.
Operational time	Dictated by displacement procedure.	Dictated by displacement procedure & fluid conditioning.	Dictated by displacement procedure.	Dictated by displacement procedure & fluid conditioning.
Clean-up to Rig	Applicable. Pit volume & Production Test. Separator considerations needed.	Applicable. Pit volume & Production Test. Separator considerations needed.	Applicable. Pit volume & Production Test. Separator considerations needed.	Applicable. Pit volume & Production Test. Separator considerations needed.
Clean-up to Flowline	Applicable. TCT consideration needed. Downstream process compatibility consideration needed.	Applicable. TCT consideration needed. Downstream process compatibility consideration needed.	Applicable. Flowline temperature consideration needed. Downstream process compatibility consideration needed.	Applicable. Flowline temperature consideration needed. Downstream process compatibility consideration needed.

Table 4: Example of a mobile water-based SRF

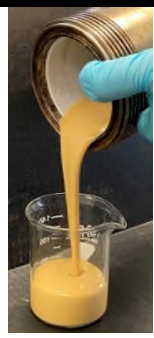
Static Aged, 120 hr, 266 °F	Static Aged, 240 hr, 266 °F
	

Table 5: Example of an immobile NAF SRF

Static Aged, 3 months, 266 °F


Table 6: Example Mobility of Different 10 lb/gal (1.20 SG) SRF after 3 months static ageing at 180 °F (82 °C)

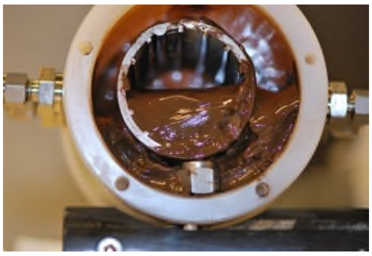
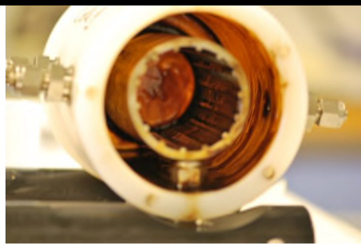
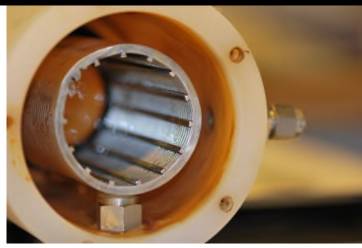
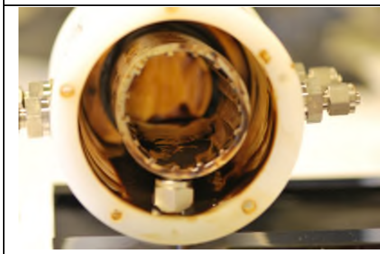
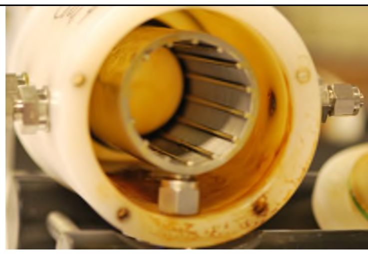
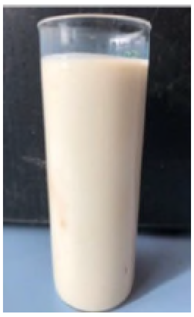
Conditioned NAF RDF (mineral base oil)	SRF (mineral base oil)	SRF (IO base oil)
	 1 month	 1 month
	 3 months	 3 months

Table 7: Example of a good NAF SRF Syneresis Test

	Initial	72 hrs	2 weeks	8 weeks
Static Aged, 226 °F				
Free Fluid on top, mL Free fluid on top, %	-	4.92 1.64	32 12.8	56.65 22.64
Mobility Left in the vessel, weight % Test Temperature, °F	-	3.95 129	8.76 133	9.73 196
Δ Drilling fluid Weight, lb/gal	-	0.08	0.5	0.56
Comments	-	Thin layer of free fluid on top, otherwise homogeneous fluid. Free moving fluid, easy to pour out of glass.	32mL layer of free fluid on top, otherwise homogeneous fluid. Free moving fluid, easy to pour out of glass.	57mL layer of free fluid on top, otherwise homogeneous fluid. Free moving fluid, easy to pour out of glass.