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Test Device Evaluates Compatibility of Reservoir Drill-In Fluid and Production Screen

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Abstract

Over the last decade, an increasing number of open-hole completions have been used to improve productivity and reservoir drainage. A variety of stand-alone sand-control devices have been developed to minimize sand production when completed in this manner. Unfortunately, overall well productivity can be limited if these devices become plugged by the reservoir drill-in fluid (RDF) prior to or during production. A portable field device has been designed to evaluate the plugging potential and allow conditioning of the reservoir drill in fluid based on real-time information. The equipment has been used successfully on a number of wells throughout the world.

The test apparatus was the result of a cooperative effort between operator and service company. The work initiated with full-size flow loops and constant-flow-rate laboratory equipment. Portability was achieved by designing a constant-pressure unit. The equipment has the built-in flexibility to evaluate any number of sand control devices. This includes wire-wrapped screens, prepacked screens, premium screens and expandable screens. Quick tests can be run in the field to determine whether the reservoir drill-in fluid (water- or invert emulsion-based) is in proper condition prior to running a specific completion assembly.

The field equipment and case history results will be detailed.

Introduction

Production screens have evolved over the years to prevent the production of sand in open-hole completions. Depending on reservoir sand size, formation integrity and expected production rates, various screens can be selected as illustrated in **Fig. 1**. In order to allow the production of reservoir fluids without the production of formation particles, the production screen must avoid being plugged with any reservoir drill-in fluid (RDF) that remains in the well after drilling operations are complete. The screen must also avoid being plugged while being positioned in the well.

Historically, if the screen becomes plugged with reservoir drill-in fluid, operators have generally relied on the use of chemical breakers to destroy the reservoir drill-in fluid. Chemical breakers will generally destroy a sufficient amount of a water-based RDF to permit production, but the removal of reservoir drill-in fluid may not be uniform and result in isolated "hot spots" of production. Chemical breakers can also react with completion assemblies altering the integrity of the screen sufficiently to allow production of sand. Localized sand production may cause the screen to catastrophically fail prematurely.

In addition, there are situations where a remedial treatment is not practical or effective. This can be due to the length of the horizontal section or lack of equipment in the well to permit chemical treatment placement to thoroughly contact the reservoir drill-in fluid or filter cake. In addition conventional invert emulsion RDF (oil and synthetic) are not effectively removed with most chemical treatments. When possible, in these instances, it may be better to design and maintain the RDF to prevent screen plugging and permit unimpeded flow through the screen. It is not practical to design the screen to be compatible with the reservoir drill-in fluid.

Reservoir Drill-In Fluid Design

Historically, reservoir drill-in fluid design has focused primarily on preventing formation damage. The primary focal points of the drill-in fluid have been fluid chemistry, filtration control, and particle sizing of bridging agents to minimize fluid and filtrate invasion into the formation. Several approaches have been taken to optimize particle size and bridging-agent concentration.[1] In addition, chemical compatibilities are evaluated and return permeability testing is undertaken to optimize the fluid. Production screen impairment is not often evaluated.

During the RDF optimization process, most work utilizes laboratory fluids. These fluids do not necessarily simulate the behavior of RDFs in the field. Drilled solids are incorporated altering fluid particle-size distribution and possibly filtercake characteristics. The incorporation of drilled solids, especially active drilled solids can dramatically impact RDF performance, especially with respect to formation damage and productivity impairment. This solids contamination has the potential to decrease the efficiency of chemical cleanup treatments as well. The impact of at least simulated drilled solids on the performance of RDFs with regard to formation damage and chemical cleanup has been evaluated. [2, 3]

Lau & Davis[2] had primarily investigated the solids tolerance of production screens to fluids with fixed D_{50} values. They tested laboratory fluids with simulated clays, but did not test various particle-size distributions with the addition of sand particles or other simulated drilled solids. Their work showed, for laboratory fluids, an approximation of the $^{1}/_{7}{}^{th}$ rule for return flow. Fluids with a D_{50} greater than one-seventh the screen opening tended to plug whereas those with a D_{50} less than one seventh the screen opening did not cause plugging. In some of their tests, it appeared that the screen was trying to plug just prior to test completion. Their tests were based on 400 mL passing through the screen.

Very little work has been undertaken to evaluate field RDFs during the drilling operation to monitor their production-screen-plugging potential. Instead, operational steps have been taken to attempt to avoid plugging.[4] These usually involve displacing the well to viscous solids-free fluids or clear completion brines. There are some risks associated with these procedures, especially displacing the open hole to completion fluid. The risks largely involve hole instability, losses or the inability to get a completion assembly to TD. In some cases it is not practical to displace to a solids-free fluid because of formation characteristics or densities required.

Production Screen Compatibility Testing

Working closely with an operator in Norway it was possible to evaluate several RDF flowback test methods. The operator has a number of fields that are completed open hole with various sand-control devices and had seen some problems with screen plugging. These include prepacked, wire wrapped, and premium screen applications. They utilize water- and oil-based fluids to drill these reservoir sections. Densities range from 9.0 – 13.7 lb/gal.

Originally, the operator had undertaken large-scale return-flow tests utilizing a length (~30 cm) of full size screen to evaluate screen plugging under radial conditions with appropriate annular volume of RDF. These tests required a large volume (~200 liter) of test fluid and proved very time consuming, but did give an indication that a properly formulated and maintained fluid would pass through a production screen. The inability to rapidly ship large volumes of field fluid to the shore-based lab and the time required to run the test did not make this test practical for drilling/completion operations.

The next instrument designed was a constant-flow-rate cell. The cell accepted a circular screen cut out sample. A small volume (1 liter) of RDF was circulated through the screen at a constant rate, normally 60 mL/min. Differential pressure across the screen was monitored to determine screen-plugging tendency. A rapid increase in pressure indicated plugging. This device was still a laboratory instrument due to the relatively delicate instrumentation (**Fig. 2**), but a sample could be sent from the rig on a helicopter and a test could be run rather quickly. This device was used to evaluate a number of field samples. Fluids were conditioned based on these evaluations and screen plugging was avoided. [5]

Laboratory Lessons Learned

The need for a device that could be utilized in the field was required to reduce waiting time and improve operations efficiency. These first two devices taught some valuable lessons. The original lab tests demonstrated:

- When plugging occurred there was a direct relationship between the screen surface area and the volume of fluid required to plug the screen. The fluid volume and surface area must be scaled properly. If insufficient fluid volume was used in the test it could give a false positive result.
- It is necessary to test the actual RDF against an actual screen sample. Screen tolerances vary across the screen. Select areas where the smallest gaps exist.
- Conventional PSD and solids evaluations did not correspond to screen plugging potential.

Field Test Unit Design

With the experience above, a constant pressure device was designed. This device was designed to provide quick results during drilling operations so that timely actions could be taken regarding reservoir drill-in fluid treatment or displacement. The device had to be durable to withstand field conditions and most importantly, test results had to compare to the already proven lab test equipment and corresponding field performance.

A device similar to a large-volume API filter press was designed to meet these objectives (**Fig. 3**). The volume of the cell was expanded to greater than one liter to address the volume/surface area factor determined in previous tests. Instead of using filter paper, three different screen holders were designed to hold samples of various production screen samples – prepacked screens, premium/wire wrapped screens, and expandable screens. Fluids are evaluated by flowing the properly scaled volume of fluid through the screen at 20 psi. The fluid either passes or fails.

For the prepacked screen holder, appropriately sized resin-coated sand is baked under a 300-micron screen. The second holder can be fitted with any wire-wrapped or premium-screen sample. Screen samples supplied by the manufacturer are fitted into the holder. Some of the screen samples can be reused depending on the size of the screen opening. The expandable screen holder permits a filtercake-covered ceramic or aloxite disk to be inserted below the screen.

For expandable screens, the procedure was also modified. Expandable screens are inserted into the well in a retracted state. The screen is expanded with a mandrel after being positioned in the well. This expands the shroud and base pipe, while spreading the overlapping fine mesh woven screens. As the expansion occurs, fluid can flow around the end of the screen or through the screen material. A series of tests were developed to simulate several scenarios during these activities of positioning the screen.

It is important to determine whether pressing the screen into the filter cake impacts screen plugging. In this case, flowing a produced fluid (oil) through the filter cake and then through the screen simulates this scenario. First, a base line is established by measuring the flow of oil through a disk/screen assembly without a filter cake at a constant pressure (**Test 1, Fig. 4**). For the remaining tests, a filter cake is built on the appropriate sized aloxite disk. Next a full configuration of filter cake, shroud, and inner woven screen (2 layers) is evaluated (**Test 3, Fig. 4**). The next scenario is the worst case, whereby the screen does not fully expand, potentially exposing filter cake to the inner woven screen. In this case, the outer shroud is eliminated in the test, placing the woven mesh directly against the filter cake. (**Test 4, Fig. 4**) Originally, one interwoven screen was tested (**Test 2, Fig. 4**), but this test was eliminated, as the results did not differ significantly from Test 3. Results demonstrate that the return flowrate varies by scenario – **Fig. 5**.

Validation Testing

Validation tests were made in the laboratory to compare performance of this constant pressure device against the constant rate device previously utilized. A close correlation between plugging was observed with each device, as can be seen in **Fig. 6**. The dotted lines represent the constant flow rate device. The pressure increases rapidly once plugging commences. The solid lines (corresponding colors represent the same fluid sample) represent the constant pressure device. Once plugging commences, the flow rate diminishes rapidly. Complete plugging occurred rapidly after plugging initiation. The time for plugging to occur was within 100 mL of volume passed on either device. This validation testing indicated that a set volume of drill-in fluid must pass through a screen to ensure no potential for plugging exists. This qualifying volume is the appropriately scaled annular volume to screen surface area.

These results also illustrated the shortcomings of trying to evaluate a fluid's plugging potential utilizing a small-volume HTHP cell. Note that one of the samples would have passed Lau and Davis' 400-mL test, but did not pass the scaled--volume test of 800 mL. This may also help explain some of Lau and Davis' results where they saw a gradual or slow rate of plugging.[2]

Field Experience

Once the instrument was validated in the lab, it was sent to the field. More than 30 units have been manufactured and are being utilized throughout the world. The devices have been used with invert emulsion and water-based fluids. They have been used to verify fluid condition against prepacked screens, multilayered premium screens, sintered-metal premium screens, wire-wrapped screens and expandable screens. Most fluids have been low-solids water-based reservoir drill-in fluids, but oil-based fluids to 13.9 lb/gal have also been evaluated.

For the 13.9-lb/gal oil-based fluid, the shale shakers were dressed with 250-mesh screens while drilling the last 984 feet of a 6448 feet 9½-in. horizontal section. While drilling the last 656 feet, the fluid consistently passed the production screen flowback test. Once the well was completed with a premium screen, it cleaned up during production.

The screen tester is used regularly with 10.5-lb/gal sized salt water-based fluids and a 12/20 prepacked screen. In one application, the sized salt fluid was used to drill the first leg of a bilateral. The screen was run in this interval. The fluid was recycled to drill the second lateral. The production screen test indicated the fluid would plug the screen once this interval was drilled. The well was displaced to a fresh, acceptable fluid prior to running the screen. Both laterals are producing based on isotope-tracer evaluations.

The screen tester has also been used on numerous wells that have utilized expandable screens as well. This includes water and invert emulsion fluids with densities from 8.9 to 11.3 lb/gal. As a general practice, the reservoir drill-in fluid is conditioned over fine mesh shaker screens to pass the production screen test or displaced to solids-free or brine-based fluid prior to running the expandable screen. If the screen is run in mud, it is recommended to test whole fluid through the screen as well as the earlier tests described. There are no reported incidents of plugging expandable screens when following these procedures.

Conclusions

Reservoir drill-in fluids should be evaluated in the field for their ability to flow through a specific completion-assembly screen. Evaluating a lab formulation or simulated field mud is not adequate.

Laboratory or field measurements of particle-size distribution, D_{50}, D_{90}, and solids concentration are insufficient to determine whether a given reservoir drill-in fluid will flow through a specific production assembly.

A simple field device can be fitted with samples from one of a variety of sand-control devices (wire wrapped, prepacked, multilayered premium and expandable screens) to provide a quick, real-time evaluation of the flowback potential. This information can be utilized in decision making to condition the fluid or displace it with a more completion compatible fluid.

The apparatus can also be used at mixing facilities to help quality control the finished product, ensuring polymers have been adequately sheared and hydrated.

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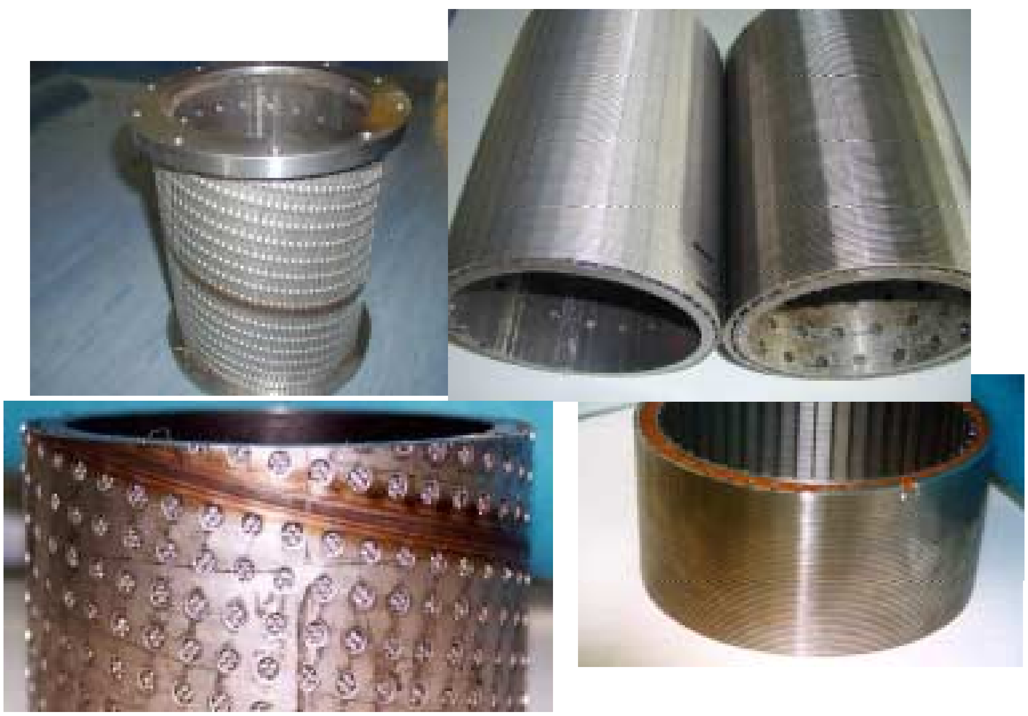

Fig. 1 - Various sand control screens.

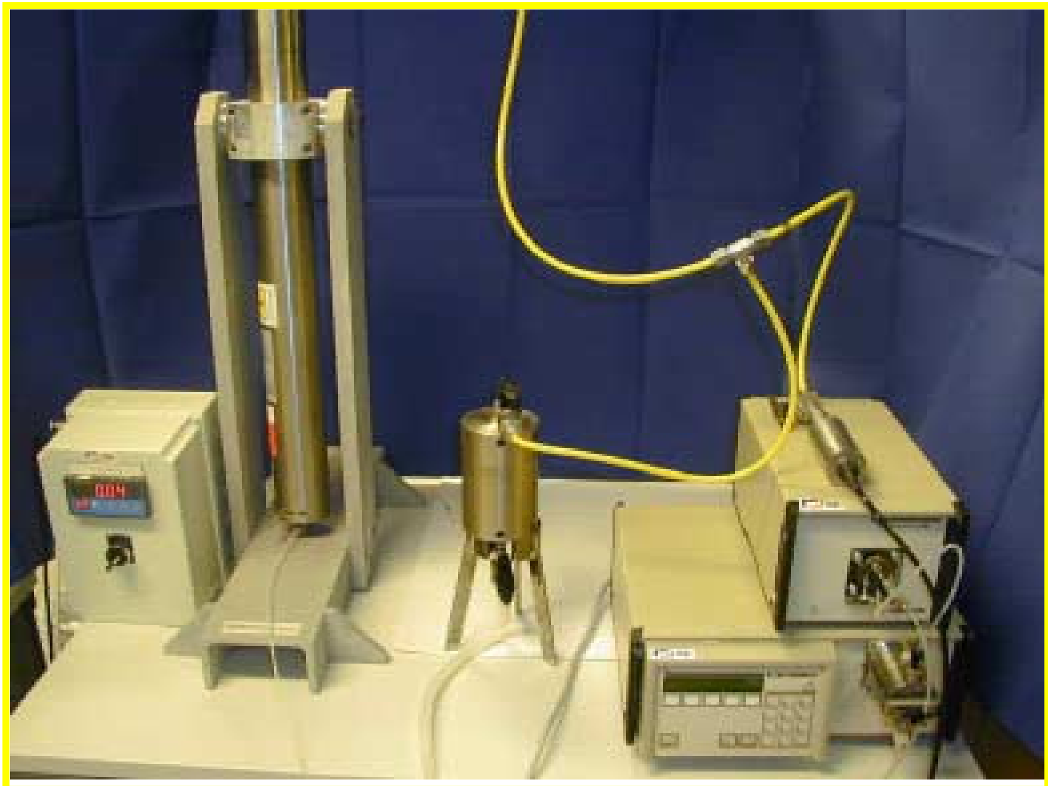

Fig. 2 – Constant-rate laboratory production screen plugging equipment.

Fig. 3 – Constant-pressure production screen plugging equipment.

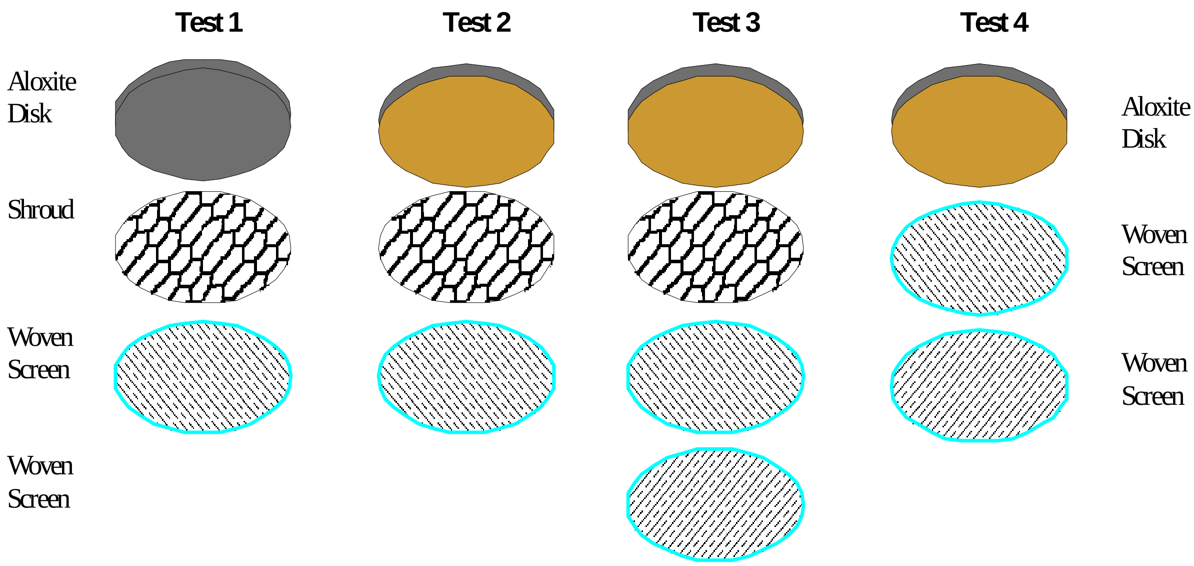

Fig. 4 – Expandable screen test sequence.

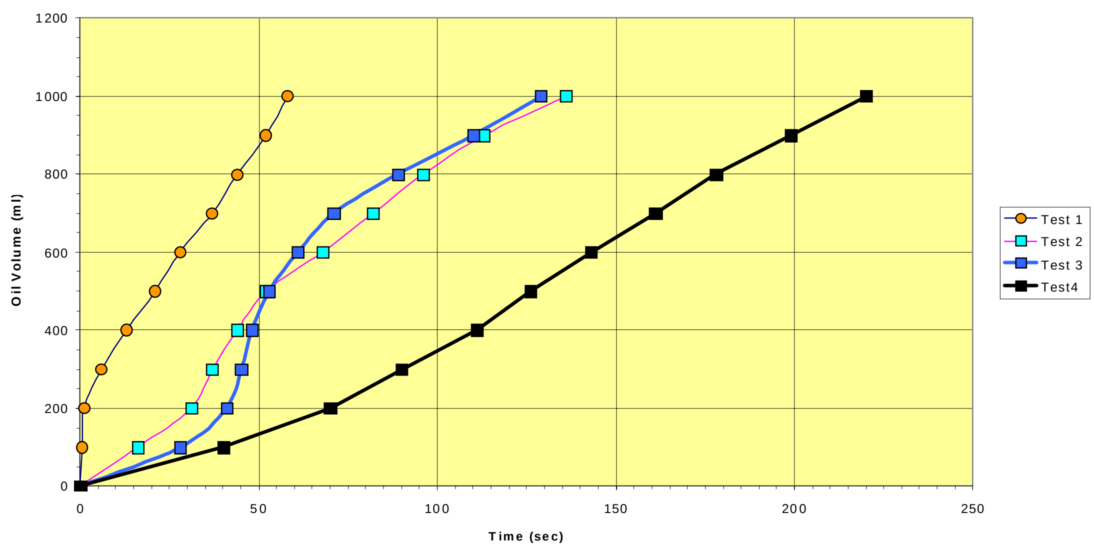

Fig. 5 – Expandable screen test results using a 9.5-lb/gal oil-based mud.

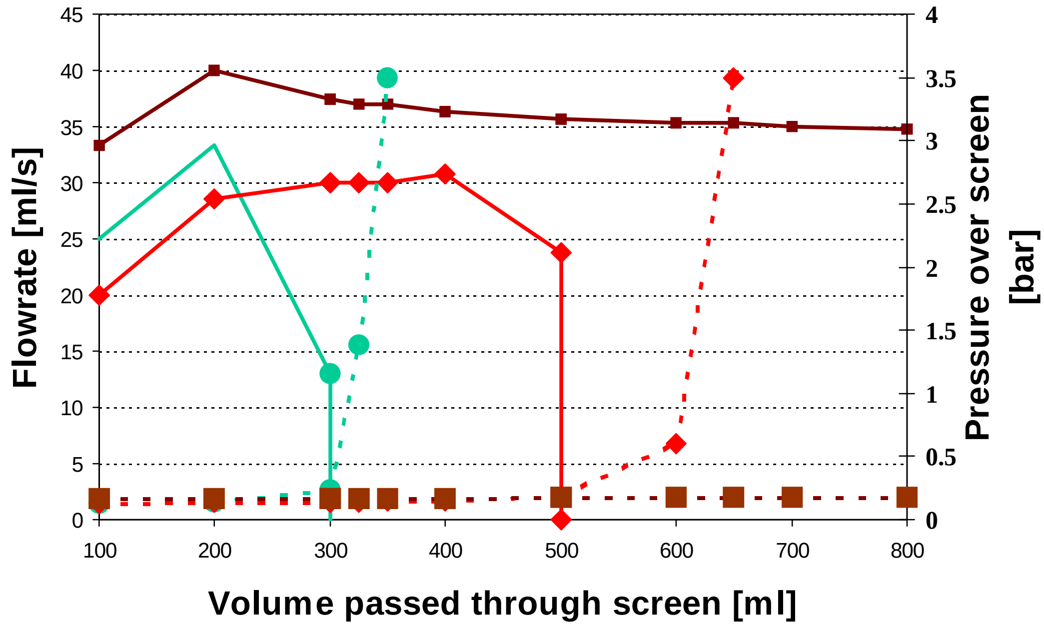

Fig. 6 - Constant pressure (dotted lines) vs. constant flow rate (solid lines).