Developing a Methodology to Characterize Formation Damage (Pore Plugging) due to Fines Migration in Sand Control Tests

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Abstract

Stand-alone screens (SAS) have been widely used in steam assisted gravity drainage (SAGD) operations. Although many researchers investigated the flow performance of SAS through sand control tests, the formation damage (pore plugging) due to fines migration has not been characterized under multi-phase flow conditions. In this study, a methodology is developed to quantify and characterize the fines migration under multi-phase flow sand control testing conditions.

A large-scale sand retention test (SRT) facility is used to investigate the flow performance of SAS. Duplicated sand samples with similar particle size distribution (PSD), shape, and mineralogy properties to the McMurray Formation oil sands are obtained by mixing different types of commercial sands, silts, and clays. Oil and brine are simultaneously injected into the sand-pack at different water-cut levels and liquid rates to emulate the changing inflow conditions in SAGD operations. The saturation levels in each flow stage are measured to determine the relative permeability values. Next, the relative permeability curves of the duplicated sand-pack sample are measured following the steady-state method. Finally, the pressure data obtained from the SRT in each flow stage are coupled with the relative permeability values to calculate the retained permeability as the indicator of flow performance of SAS'.

Generally, testing results show that single-phase oil flow generates minor and negligible permeability impairments in the near-screen zone of the sand-pack. An evident permeability reduction is observed once the water breakthrough happens, indicating that the wetting-phase fluid significantly mobilizes fine particles and causes pore plugging. Also, with the increase of flow rate and water cut, a further reduction in permeability is found as a result of the higher drag force and greater exposure area of fines to brine.

The proposed methodology presented in this study allows quantitative characterization of the formation damage under multi-phase flow condition and provides a practical and straightforward method for the evaluation of the SAS's flow performance.

Key Words: Stand-Alone Screens, Flow Performance, Formation Damage, Fines Migration.

1. Introduction

Canadian oil sands, with an estimated 170 billion barrels of bitumen in place, are known as the third largest heavy oil reserves in the world (Lunn, 2013; Wilson, 2013). Most of the heavy oil resources in Canada are located in Alberta. Athabasca, Peace River, and Cold Lake are the main prolific and exploited areas, as shown in Fig. 1 (Butler, 2001). Steam assisted gravity drainage (SAGD) has been established as the effective technique to recover heavy oil in Alberta's oil sands (Butler and Stephens, 1981; Butler, 1985; Gates et al., 2005; Zhang et al., 2007).

The SAGD operation consists of a pair of horizontal wells separated by a vertical distance of around five meters. Typical SAGD wells extend from 500 to 1200 meters in the horizontal section (Butler, 1998; Nasr et al., 1998; Dang et al., 2010). The SAGD process relies on steam injection from the upper injection well into the formation to reduce the viscosity of the bitumen. Upon the progressive growth of a steam chamber, the melted bitumen and condensed steam flow toward the lower production well along the edge of the steam chamber. SAGD projects attempt to achieve recovery factors higher than 50% (Butler and Stephens, 1981; Butler, 2001). Fig. 2 schematically shows the cross-section view of the steam chamber in SAGD.

Fig.1 Heavy oil resources in Alberta, Canada (modified from Butler, 2001)

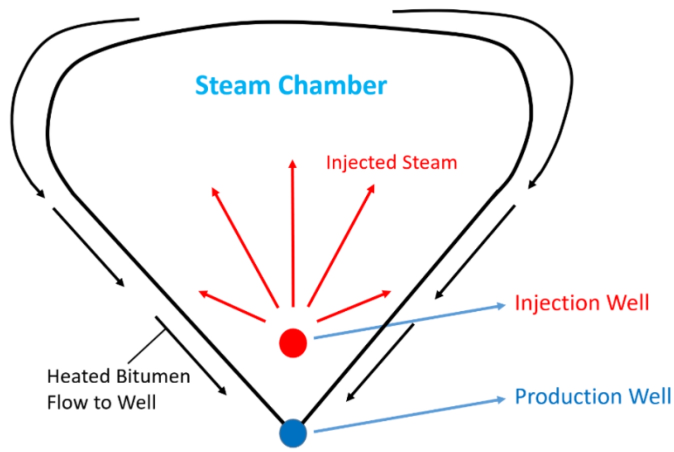

Fig.2 Schematic concept of the steam chamber in SAGD (modified from Butler, 1985)

Sand production is a significant issue for the thermal exploitation of unconsolidated oil-bearing sands (Yi, 2002; Han et al., 2007; Dong et al., 2014; Anderson, 2017). The produced sand can cause damage to down-hole facilities and pipelines, plug the wellbore and expensive remedial operations (Al-Awad et al., 1999; Denney, 2008; Sanyal et al., 2012).

Formation damage due to fines migration is another key factor affecting the reservoir deliverability, especially in thermal operations. The high temperature in SAGD operation can facilitate the fines migration and plugging (Rodriguez and Araujo, 2006; Rosenbrand et al., 2015; Yang et al., 2018; You et al., 2019). Also, clay mineralogy could change at the thermal condition. Kaolinite can change to smectite in the temperature range of 160 to 300 ℃ (Imasuen et al., 1989). Smectite can swell with the contact of water and cause permeability reduction (Civan, 2007; Aksu et al., 2015).

Different sand control devices (SCD) are installed in SAGD wells to prevent the sanding and maintain effective and safe production operations. Among them, stand-alone screens (SAS) including slotted liner (SL), wire-wrapped screen (WWS), and punched screen (PS) are widely used in the SAGD as completion strategies due to their low cost and relatively easy deployment (Bennion et al., 2009; Xie, 2015; Mahmoudi et al., 2016a; Montero Pallares et al., 2018b; Wang et al., 2018). The two main functions of these SAS are to control the sand production while maintaining the reservoir deliverability.

Several studies have investigated the sanding and flow performances of different SAS. There are several important factors affecting the performance of SAS including operational conditions such as flow rates, production ramp-up rates (Ballard and Beare, 2006; Bennion et al., 2009; Chanpura et al., 2012b; Jin et al., 2012; Romanova et al., 2014) and formation properties such as the PSD, fines content (Constien and Skidmore, 2006; Williams et al., 2006) and producing fluid properties such as water cut (Wu et al., 2006; Joseph et al., 2011), and brine pH and salinity (Mahmoudi et al., 2016a; Montero Pallares et al., 2018b). These factors must be considered in the selection and design of any SCD. OFA, aperture size, and slot density are the key design specifications controlling the response of SCD's (Mahmoudi et al., 2016a; Fattahpour et al., 2018).

Experimental sand control testing is widely used in the industry to analyze SAS's performance (Ballard and Beare, 2006; Constien and Skidmore, 2006; Williams et al., 2006; Bennion et al., 2009; Chanpura et al., 2012b; Romanova et al., 2014; Devere-Bennett, 2015; O'Hara, 2015; Mahmoudi et al., 2016a; Anderson, 2017; Ma et al., 2018). Currently, there are two types of sand control testing methods: slurry SRT and pre-packed SRT. In the slurry test, low-concentration sand slurry (less than 1% by volume) is pumped at a constant flow rate towards the screen. A sand-pack gradually forms on the screen during the test, which simulates a gradual formation collapse around the borehole (Gillespie et al., 2000; Underdown et al., 2001; Ballard and Beare, 2006; Williams et al., 2006; Mathisen et al., 2007; Chanpura et al., 2012a).

In the pre-packed SRT, it is assumed that the borehole has fully collapsed over the screen, filling the annulus space between the borehole and the screen with formation sand. Therefore, a sand sample is deposited directly over the screen to emulate this scenario. Next, fluids are injected through the sand-pack toward the screen coupon, and pressure changes along the sand-pack and sand production are measured during the test. Generally, it has been accepted that pre-pack testing is a better representation of the wellbore condition in SAGD operations (Ballard and Beare, 2006; Constien and Skidmore, 2006; Williams et al., 2006; Bennion et al., 2009; Chanpura et al., 2012a; Romanova et al., 2014; Devere-Bennett, 2015; O'Hara, 2015; Anderson, 2017).

In previous pre-packed SRT studies, the sanding performance of SAS has been extensively investigated. However, the flow performance of SAS has often being a point of discussion due to the deficiencies of some studies in implementing objective flow performance indicators (Chanpura et al., 2011). For instance, rigid pressure drop values such as 5 psi for pre-packed testing (Romanova et al. 2014; Devere-Bennett, 2005; O'Hara, 2005) and 100 psi for slurry testing (Ballard et al. 1999; Williams et al., 2006) have been used to evaluate the flow performance of SAS. These values have not been justified, and the pressure response during a test is not only the result of the screen interaction but also the sand pack itself. Therefore, pressure readings are strongly related to the type of sand implemented and do not allow a proper comparison between different PSD's (Montero Pallares et al. 2018a).

Hodge et al. (2002) and Mahmoudi et al., (2018) proposed to use retained permeability as the flow performance indicator of SAS in the sand control testing. The retained permeability is defined as the ratio of screen permeability over the initial permeability of the sand-pack (Hodge et al., 2002). Ideally, the retained permeability should be close to 100%. However, in oil reservoirs, due to fines migration and pore plugging, a drastic permeability reduction around production wells is observed (Sharma and Yortsos, 1986; Sarkar and Sharma, 1990; Ohen and Civan, 1991; Denney, 1998; Bybee, 2002; Qiu et al., 2008; Bedrikovetsky et al., 2011; Zeinijahromi et al., 2011; Musharova et al., 2012; Karazincir et al., 2017; You and Bedrikovetsky, 2018). The acceptable minimum limit for retained permeability is recommended to be 50% to avoid significant productivity losses (Hodge et al., 2002; Mahmoudi et al., 2018).

Compared to the rigid pressure drop, the retained permeability quantitatively characterizes the formation damage due to fines migration and screen installation. However, in previous sand control studies, the retained permeability is only employed in single-phase flow tests (Mahmoudi et al., 2016a; Fattahpour et al., 2016; Guo et al., 2018; Roostaei et al., 2018). For multi-phase flow sand control tests, rigid pressure drop or productivity index in the near-screen zone is used to analyze the flow performance qualitatively (Bennion et al., 2009; Romanova et al., 2014; Devere-Bennett, 2015; O'Hara, 2015; Spronk et al., 2015; Anderson, 2017; Fattahpour et al., 2018).

In this study, a methodology is introduced to characterize and quantify the pore plugging by retained permeability due to fines migration under multi-phase flow condition. This methodology couples the pressure data from the pre-packed SRT with the relative permeability curve of the sand-pack to provide a quantitative parameter to assess formation damage. Later, the quantified flow performance could be employed for the optimal selection of the screen.

2. Experimental Investigation

2.1 Experimental Setup

A multi-phase flow pre-packed SRT facility was employed in this investigation. As schematically shown in Fig. 3, the SRT facility comprises of five major units; 1) sand-pack cell, 2) data acquisition and monitoring unit, 3) fluid injection unit, 4) sand and fines measurement unit, and 5) back-pressure unit.

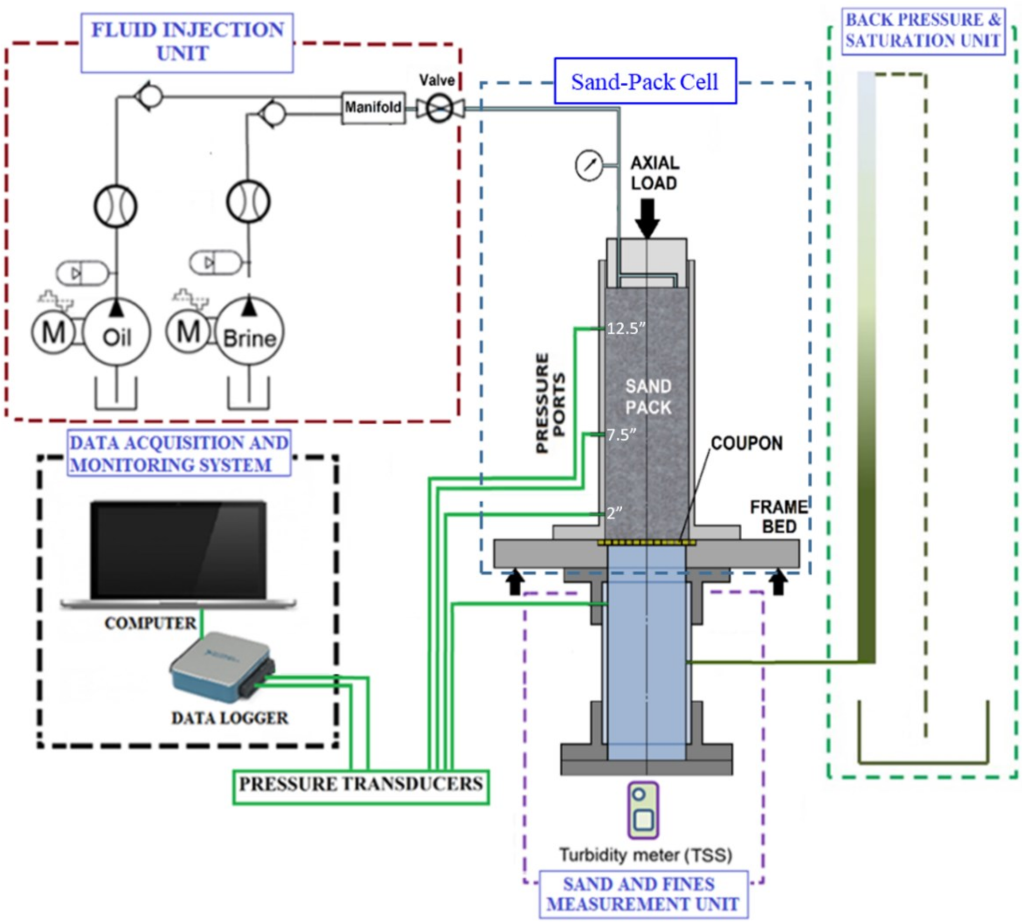

Fig. 3 Schematic view of SRT setup

The SRT cell with an inner diameter of 6 inches and a total length of 16.5 inches accommodates 6-inch-diameter exchangeable liner coupons including WWS, PS, and SL. Three pressure ports are installed along the cell to record the pressure readings during the test. The first pressure port is located two inches above the coupon to measure the pressure drop near the screen (bottom segment). The next two pressure ports are placed 7.5 inches and 12.5 inches above the coupon to measure the pressure drop in the middle and top segments. The middle segment is from 2 inches to 7.5 inches in height, and the top segment is between 7.5 and 12.5 inches. The pressure differential measurement unit consists of three differential pressure transmitters with 0.25% full-scale accuracy plus the data acquisition system (LabVIEW). The fluid injection unit consists of brine and oil pumps. Two triplex solenoid diaphragm metering pumps are used for brine and oil injection. Liquid injection rates are measured by two weight scales with 0.1% full-scale accuracy, and the discharged rates are measured by a graduated cylinder. Producing fluids are discharged through a back-pressure column which provides around 3 psi of back-pressure.

2.2 Testing Material

2.2.1 Sand-pack

Duplicated sand-pack samples were used in this large-scale SRT testing due to their reasonably low cost and availability. Also, duplicated sand-packs ensure repeatability control on every test, unlike the high heterogeneity of real formation sands. The sand-pack samples were obtained by mixing different kinds of commercial sands, silts, and clays to replicate the oil sands from the McMurray Formation (Mahmoudi et al., 2016b). The sand-pack samples have the same PSD of the real formation sand. The PSD's of oil sands in the McMurray Formation have been categorized into four major classes, as shown in Fig. 4 (Abram and Cain, 2014). Among them, DC-I and DC-II are fine sands, and DC-III and DC-IV are medium and coarse sands, respectively.

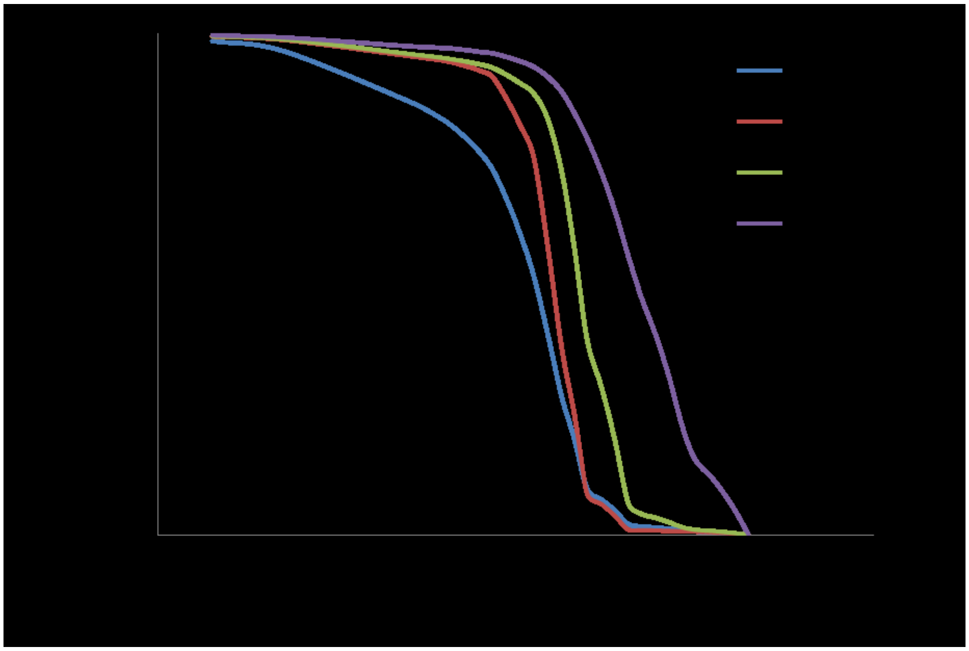

Fig. 4 PSD classes of McMurray Formation oil sands (Abram and Cain, 2014)

This study employed the DC-III PSD type for the testing program. Fig. 5 shows PSD's of commercial sands, silts, and clays that were used in the replication of the real PSD of DC-III oil sands.

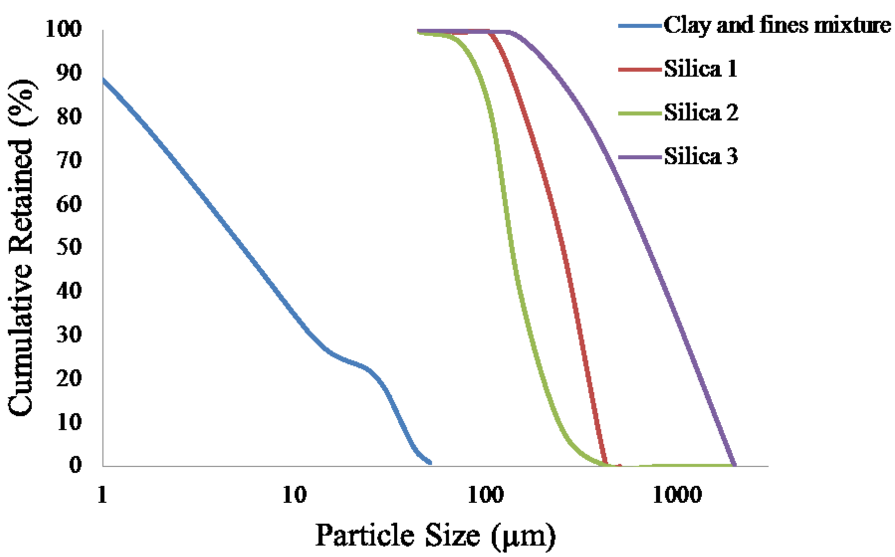

Fig. 5 PSDs of different commercial sands, silts, and clays

Fig. 6 compares the PSD between the duplicated sand-pack sample and the actual DC-III formation sand, which shows a reasonable overlap. The duplicated sand-pack sample contains

5.4 wt% of fines, 66.1 wt% of Silica 1, 25.7 wt% of Silica 2, and 2.9 wt% of Silica 3. Kaolinite and illite are used as the clay material in the sand-pack sample as they are the dominant clay types in the McMurray Formation (Romanova et al., 2015; Mahmoudi et al., 2016a).

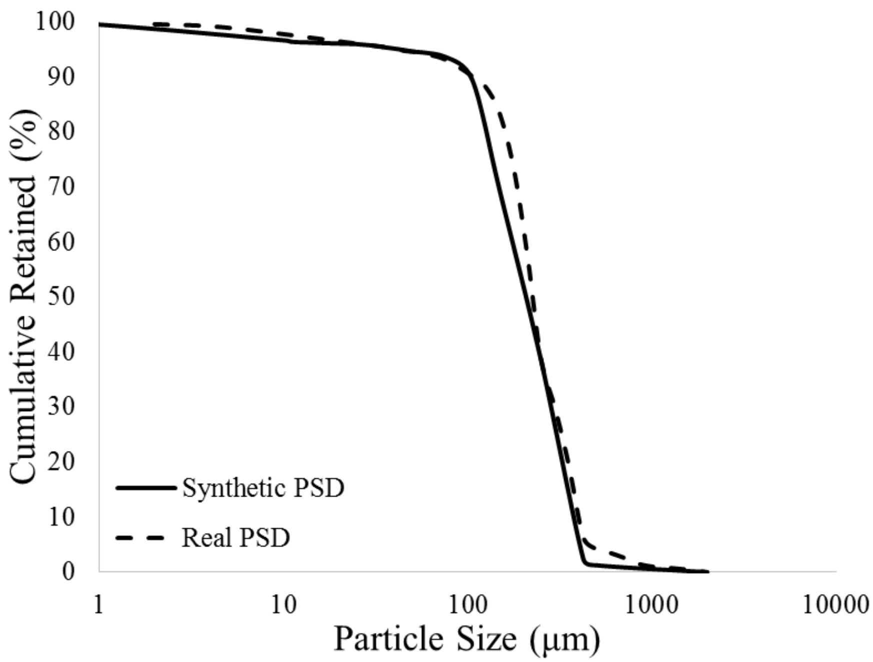

Fig. 6 PSD matching result

2.2.2 Flowing Fluids

Sodium Chloride brine with the salinity of 400 ppm and pH of 7.9 was injected as the water phase. A review of the characteristic from produced water in SAGD waters shows 400 ppm as the lowest salinity and 7.9 as a typical pH level (Mahmoudi et al., 2016c).

Regarding the oil phase, mineral oil with a viscosity of 8 cp at laboratory temperature (20℃) is injected. The oil viscosity emulates the actual downhole oil viscosity for the SAGD operations (Romanova et al., 2014).

2.2.3. SAS Coupons

SAS coupons are used in this experimental investigation to compare their flow performance under multi-phase flow condition. The coupons are 6-inch-diameter disks that emulate direct cut-outs from real liners. In this study, SL, WWS, and PS coupons are employed in the testing program, as shown in Fig. 7. The SL coupons have different slot densities in slots per foot (SPF).

The SL coupon used in this study has a slot density of 216 SPF. The OFA of each coupon is provided in Table 1.

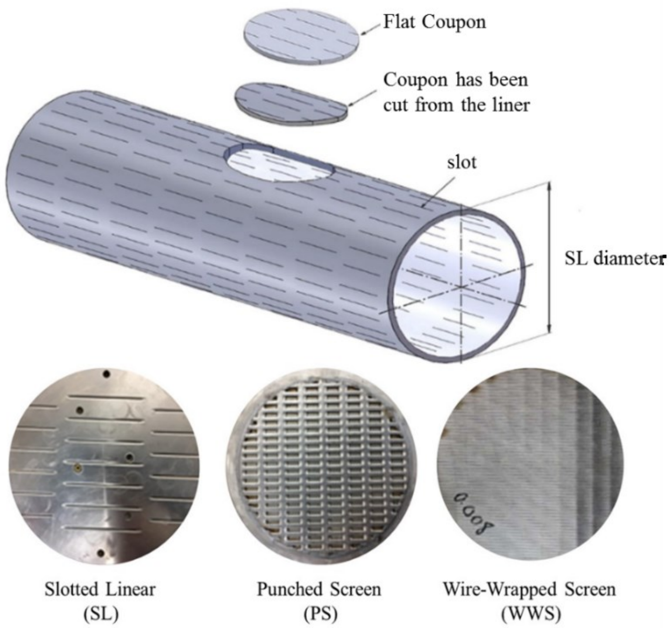

Fig. 7 Schematic view of different types of liner coupons

Table 1 OFA of the coupons used in this study

SAS Type	Aperture (inches)	OFA (%)
SL	0.014	3
SL	0.018	4
WWS	0.014	14
WWS	0.018	18
PS	0.014	5.2
PS	0.019	7

2.3 Testing Procedure

The SRT testing procedure consists of (1) preparation of the sand-pack sample by mixing the commercial sands, (2) assembling the SRT cell, (3) packing the sand, (4) saturation of sand-pack,

(5) fluid injection, (6) saturation tracking and pressure measurement, and (7) disassembling the SRT cell. All tests followed the same procedure.

The dry commercial sands are mixed by a mixer for 20 mins to achieve a uniform particle distribution. Then, 10 wt% of brine (400 ppm) is added and mixed with the dry sand-mixture to produce a uniformly moist sand-mixture sample. Next, the moist sand sample is packed into the SRT cell in a layer-by-layer method to achieve a uniform porosity of 38%. After the sample packing, a top platen is installed and axial load of about 60 psi is applied on the sand pack.

The testing procedure consists of several stages shown in Fig. 8. First, the sand-pack is saturated with brine at 500 cc/hr flow rate from the bottom of the sand-pack toward the top to displace the air and avoid premature damage on the sample (Stage 1). Next, the absolute permeability of the sand-pack sample is measured by flowing brine from the top of the sand-pack toward the bottom (Stage 2). Later, the injection scheme follows at different stages, as shown in Fig. 8. The fluid injection initiates with single-phase oil flow (Stages 3-5) and changes to two-phase brine and oil flow (Stages 6-10) to capture changing flow conditions encountered in SAGD wells. Different water cut (WC) levels are employed during the two-phase flow stages; i.e., 50%, 75% and 100% water cut levels.

The normalized flow rates in this study are selected based on the applicable SAGD production rate; 4000 bbl/day for an 800-m and 7-inch-diameter production well (Mahmoudi et al., 2016a; Montero et al., 2018a). Three different effective flow percentages (50%, 30%, and 20%) are applied to this SAGD production rate to account for varying levels of slots plugging and non-uniform flow along the well (Romanova and Ma, 2013).

During the SRT testing, pressure readings are recorded for each flow stage at the steady-state condition. Also, the average saturation is measured for each flow stage by the external method which relies on the mass balance. The mass injected (M_{in}) into the sand-pack minus the mass discharged (M_{out}) from the sand-pack equals the mass accumulated in the sand-pack, which yields the average saturation. The M_{in} of brine and oil are measured by two scales with 1-gram accuracy. The M_{out} of brine and oil are measured by scales and graduated cylinders with 2 cc accuracy.

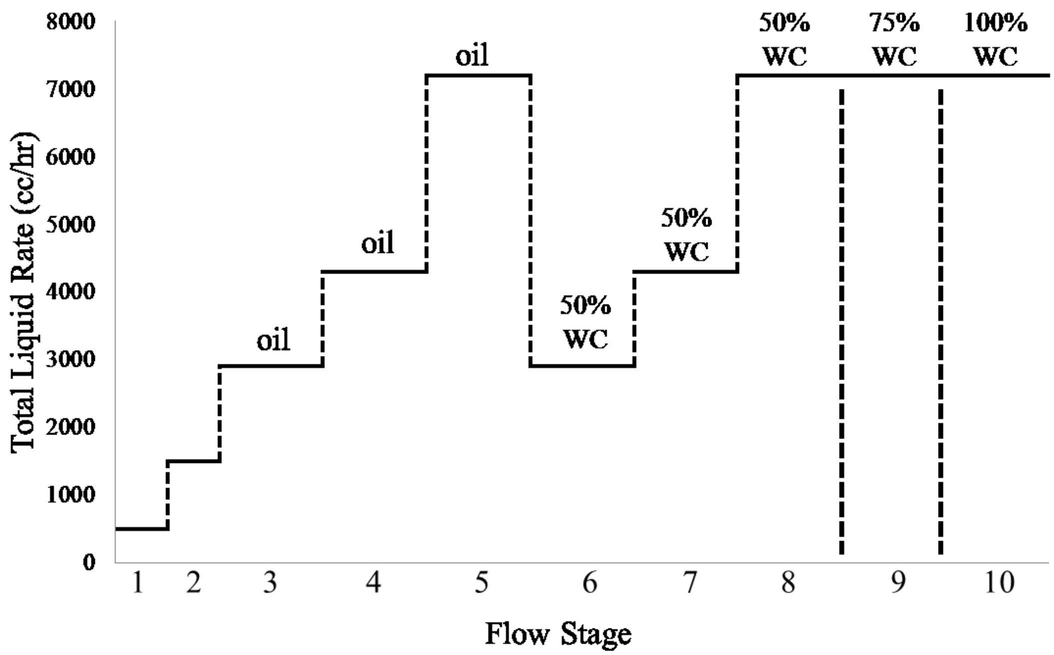

Fig. 8 Testing procedure of SRT

2.4 Testing Matrix

This study implements 6 SRT tests, as shown in Table 2. Two aperture sizes are selected for each SAS. The aperture sizes are chosen based on the current design criteria in the literature (Coberly, 1937; Bennion et al., 2009; Fermanuik, 2013; Mahmoudi et al., 2016a; Montero et al., 2018b). This test matrix allows investigating the flow performance of different screen types and the role of slot width in the response of SCD's.

Table 2 Testing matrix

SAS	Aperture Size (inches)	
SL	0.014	0.018
WWS	0.014	0.018
PS	0.014	0.019

3. Methodology for Formation Damage Characterization

This section introduces the proposed methodology for the characterization of formation impairment due to fines migration in sand control testing.

3.1 Concept of the Methodology

The pressure-drop readings from the SRT indicate the evolution of formation damage (pore plugging), the flow performance of screens and the impact of screen design on flow impairment implicitly. The absolute permeability reduction is a clear indicator of pore damage. From the multi-phase Darcy's Law (Eqs. 1 and 2), the relative permeability of the phases at specific saturation levels are necessary to obtain the absolute permeability. Afterward, the retained permeability could be calculated as the indicator of formation damage and flow performance at different fluid ratios (Eq. 3).

In this paper, a new methodology is proposed to characterize the fines migration under the multi-phase flow condition. The methodology relies on the combination of the pressure recordings from the SRT and the relative permeability curves of the sand-pack sample. The importance of this methodology is the establishment of relative permeability curves at the initial condition, in which there is no or only minor formation damage during the measurements. Then, these curves obtained at initial condition will be used as a baseline in the absolute permeability calculations (Eqs. 1 and 2). In other words, relative permeability values are assumed to be independent of fines migration, hence, constant for each flow stage. Therefore, for each flow stage in the SRT, the absolute permeability could be obtained.

$$q_{w}=\frac{k_{abs}k_{rw}\Delta P}{\mu_w A} \tag{1}$$

$$q_{o}=\frac{k_{abs}k_{ro}\Delta P}{\mu_o A} \tag{2}$$

$$Retained\ Permeability\ (\%)=\frac{k_{abs\ @each\ flow\ stage\ in\ the\ near-screen\ zone}}{k_{abs@initial\ condition}} \tag{3}$$

3.2 Relative Permeability Curves Measurements

The measurements of the relative permeability curves for the duplicated sand-pack samples consist of relative permeability and saturation determinations. Penn State steady-state method (Honarpour and Mahmood, 1998) is used in the relative permeability determination because (1) the Penn State apparatus has similar characteristics with the pre-packed SRT facility, (2) capillary end effects can be avoided in both apparatuses, and (3) low fluid flow rates can be applied to prevent core damage (Firoozabadi and Aziz, 1986; Rose, 1987). The saturation is obtained by the external method. The external technique relies on the mass balance concept. The mass difference between inlet and outlet is the mass accumulated in the sand-pack, which yields the average saturation (Honarpour and Mahmood, 1998). Detailed relative permeability and saturation measurements are discussed in the below sections.

3.2.1 Relative Permeability Determination

The relative permeability curves for the duplicated sand-pack sample are measured at low flow rates and high salinity values compared to ones in the SRT to obtain the relative permeability curves without inducing fines migration. It has been reported that there is Critical Salt Concentration (CSC) for fines release and mobilization (Khilar and Fogler, 1984). Below the CSC, there is minor fines migration. Also, the flocculation rate of fines increases when the electrolyte concentration increases (Kotylar et al., 1996). Therefore, using lower flow rates and higher salinity values (10,000 ppm) in the relative permeability test compared to the SRT test condition (400 ppm) allows establishing the relative permeability curves at the initial condition. Also, the injection scheme implemented during the relative permeability measurements is consistent with that of the SRT to avoid capillary-hysteresis effect.

The procedure starts with sample saturation with brine and absolute permeability measurement (Stages 1 and 2 in Fig. 9). Then, oil is injected into the sample and displaces the brine to irreducible water saturation (Stage 3). Next, two-phase flow conditions with three different water cut values are employed to obtain the relative permeability curves (Stages 4-6). Finally, brine is injected to measure the relative permeability at residual oil saturation (Stage 7).

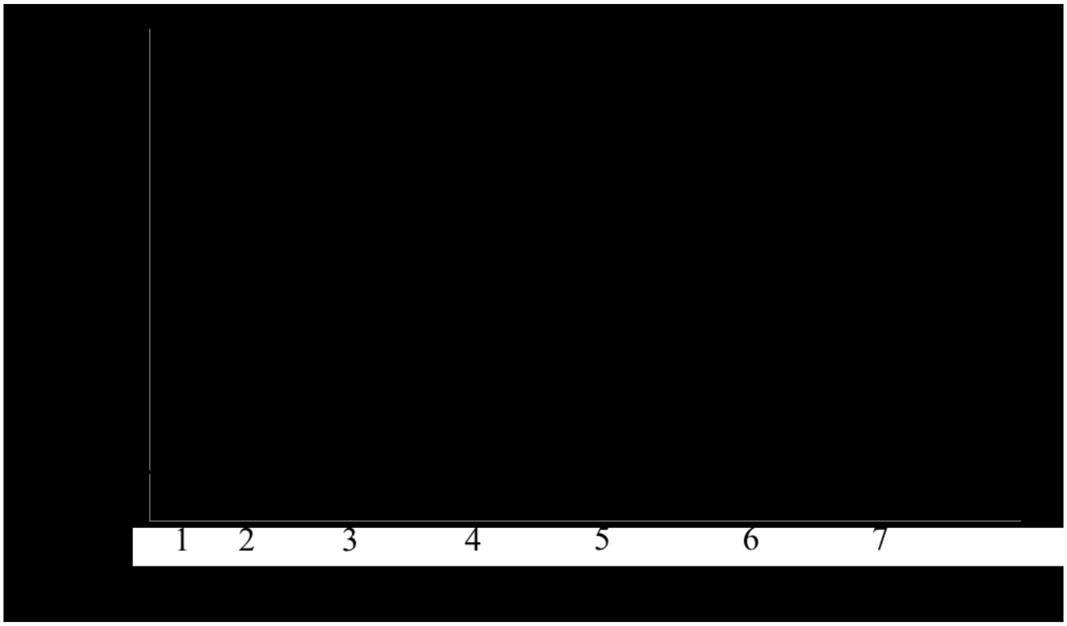

Fig. 9 Testing procedure for relative permeability measurements

A sample relative permeability calculation is given below: The absolute permeability of the duplicated DC-III sand sample is 2400 md, at q_{water}= 1875 cc/hr and $q_{oil} = 625\, cc/hr$, the pressure recorded at steady-state was ΔP= 0.93 psi. Using Eq. 1 and Eq. 2, $k_{ro} \cdot k_{abs}$= 1528 md and $k_{rw} \cdot k_{abs}$= 573 md. The relative permeability to oil (k_{ro}) and water (k_{rw}) can easily be obtained as 0.63 and 0.24, respectively.

3.2.1 Saturation Determination

The average saturation values are obtained through the external method, where the mass of brine and oil injected into the sand-pack sample is recorded as M_{in} and the mass produced out of the sample is recorded as M_{in}. The mass accumulated inside the sample (M_{am}) equals the difference between M_{in} and M_{out} which yields the average saturation. Equation 4 shows the brine saturation calculation.

$$\mathrm{S}_W = \frac{M_{in(water)} - M_{out(water)}}{\rho_w \cdot V_{pore}} \tag{4}$$

Table 3 shows saturation values for each flow stage in the relative permeability measurement.

Table 3 Water saturation of each flow stage

Flow stage	S_W (%)
irreducible water	28.0
WC=0.25	46.2
WC=0.5	53.0
WC=0.75	60.1
WC=0.85	67.2
residual oil	73.0

3.2.3 Relative Permeability Curves

The relative permeability curves are plotted in Fig. 10 by using the relative permeability values and the corresponding saturation levels. Now, these relative permeability curves can be combined with the pressure recordings of each flow stage in SRT tests to calculate the absolute permeability (Eqs. 1 and 2). Finally, the plugging indicator, namely, the retained permeability is obtained under the multi-phase flow condition (Eq. 3).

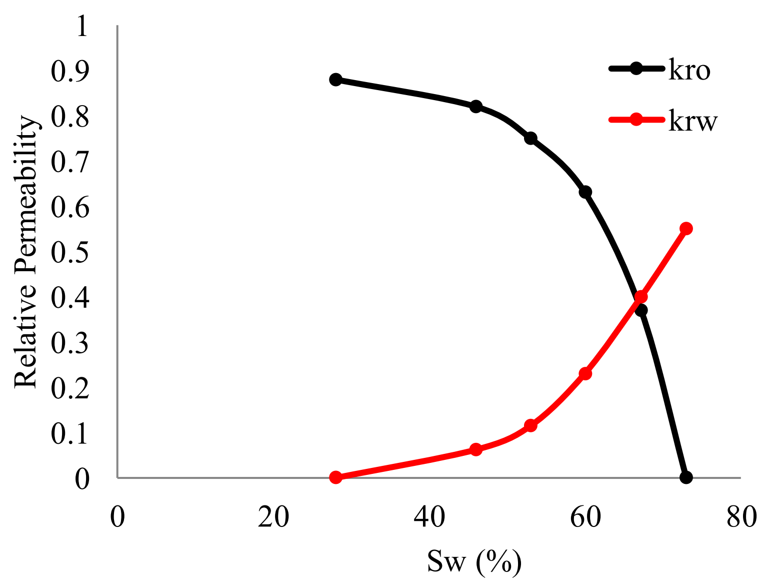

Fig. 10 Relative permeability curves for the duplicated sand-pack (DC-III)

3.3 Retained Permeability Calculation

The retained permeability is defined as the permeability in the near screen-zone over the initial sand-pack permeability (Hodge et al., 2002; Mahmoudi et al., 2018). Based on the proposed methodology, the detailed procedure of retained permeability calculation includes:

(1) Track the saturation of each flow stage in SRT.
(2) Find out the corresponding k_{rw}/k_{ro} from the measured relative permeability curves.
(3) Measure flow rates and pressure readings of each flow stage in SRT.
(4) Apply Darcy's Equations (Eqs. 1 and 2) to calculate k_{abs} of each flow stage.
(5) Obtain retained permeability of each flow stage by Eq. 3.

Table 4 shows the saturation values for each flow stage obtained from the SRT.

Table 4 Water saturation of each flow stage in SRT

Flow Stage	3	4	5	6	7	8	9	10
$\mathbf{S_W}$ (%)	31.0	29.0	28.0	53.0	53.1	53.1	60.2	73.0

A sample calculation of the retained permeability for PS (0.014'') at Stage 10 is shown below: The water saturation in this stage is 73%, and the corresponding k_{rw} from the relative permeability curves is 0.55. The measured flow rate is 7200 cc/hr, and the pressure reading is 0.83 psi. Using (Eq. 1), the k_{abs} in this flow stage is 1776 md. Therefore, by using (Eq. 3), the retained permeability is 74%.

4. Results and Discussions

In this section, the retained permeability as the plugging indicator is calculated for each flow stage of different SCD's by following the abovementioned procedure. The retained permeability quantifies and characterizes the formation damage and the flow performance of the screen.

Fig. 11 shows an example of the differential pressure readings in the near-screen section of different flow stages (stages 3 to 10 in Fig. 8) during the test for SL (0.018''). After reaching steady-state condition indicated by a stable pressure reading, the differential pressure value and corresponding flow rate are used to calculate the retained permeability by using Eq. (1), (2), and (3).

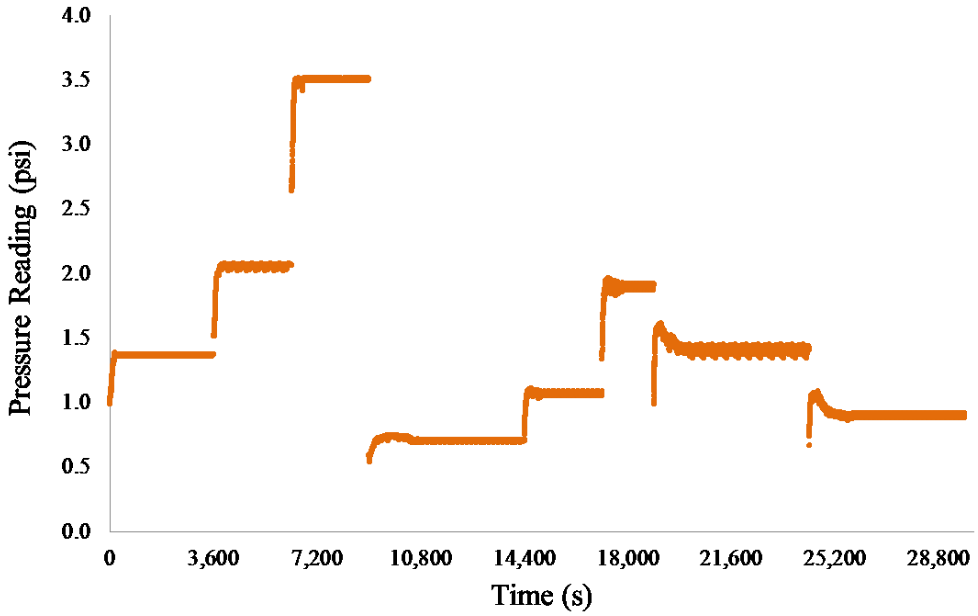

Fig. 11 Differential pressure readings in the near-screen zone (SL 0.018'')

Figs. 12-14 show the retained permeability values for different types of screens with two different aperture sizes. From these results, it is found that the single-phase oil flow at connate water saturation creates minor formation damage. This can be attributed to the water-wet behavior of the fine particles and silica sands. The fine particles attached to the pore walls are surrounded and stabilized by a static water layer that does not allow the contact with the non-wetting phase (oil). The shear force created by the oil is not strong enough to detach the fine particles from the pore walls and migrate them. Therefore, only minor permeability reduction has been observed.

A significant drop in the retained permeability is observed when water breakthrough occurs, which indicates a higher level of fines migration and pore plugging. The reason can be attributed to the flow of the wetting-phase, which creates a shear force on the fine particles and detaches them from the pore walls. This process releases the fine particles and migrates them to the near-screen zone. The fines migration causes pore plugging in the near-screen zone. Therefore, a retained permeability reduction is found after water breakthrough.

With the increase of flow rate at a constant WC (Stage 7, Fig. 8), the retained permeability becomes lower due to the stronger drag forces on the particles. Further, with the increase of WC at a constant liquid rate, the retained permeability shows a steep reduction. This can be attributed to the higher contact area between the wetting phase (brine) and fine particles. Consequently, more fines are exposed and detached by the brine.

Figure 12 to 14 shows that the retained permeability increases with the increase of aperture size. This is because the fines discharge from the sand-pack is encouraged by the increase in the aperture size. Therefore, fewer amounts of fines accumulate in the sample, and less plugging is observed.

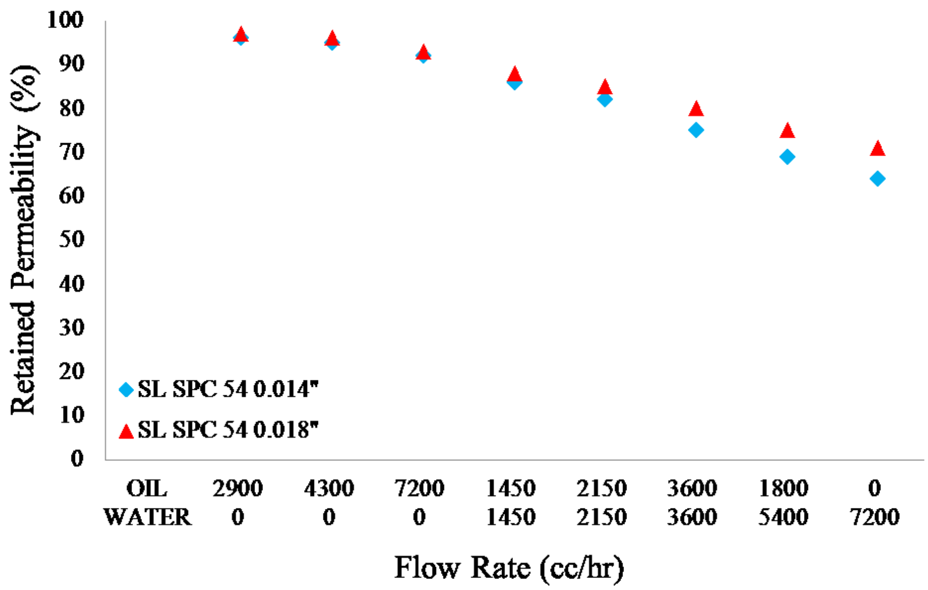

Fig. 12 Retained permeability values for SL with the aperture sizes of 0.014’’ and 0.018’’

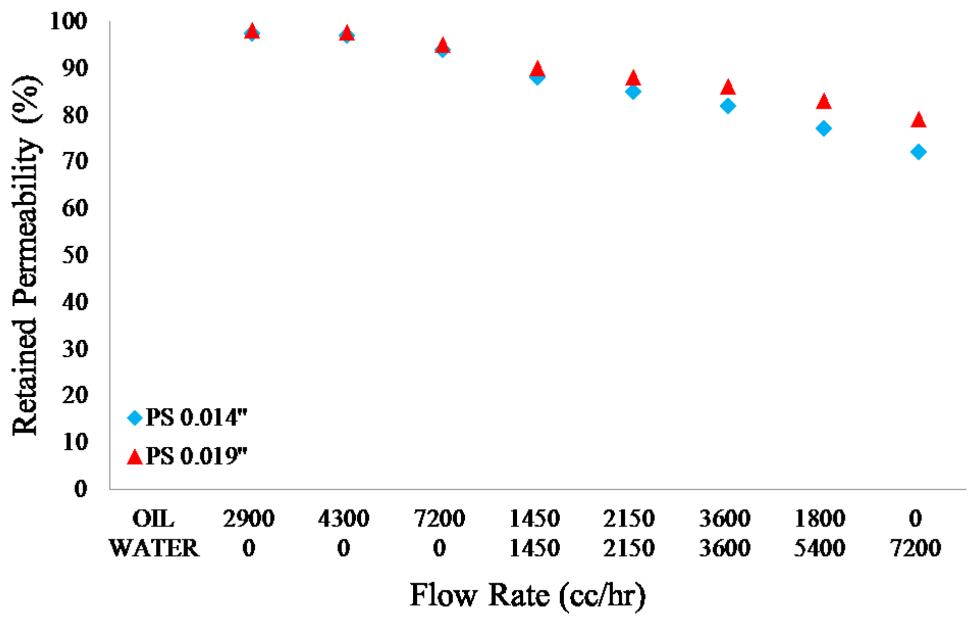

Fig. 13 Retained permeability values for PS with the aperture sizes 0.014’’ and 0.019’’

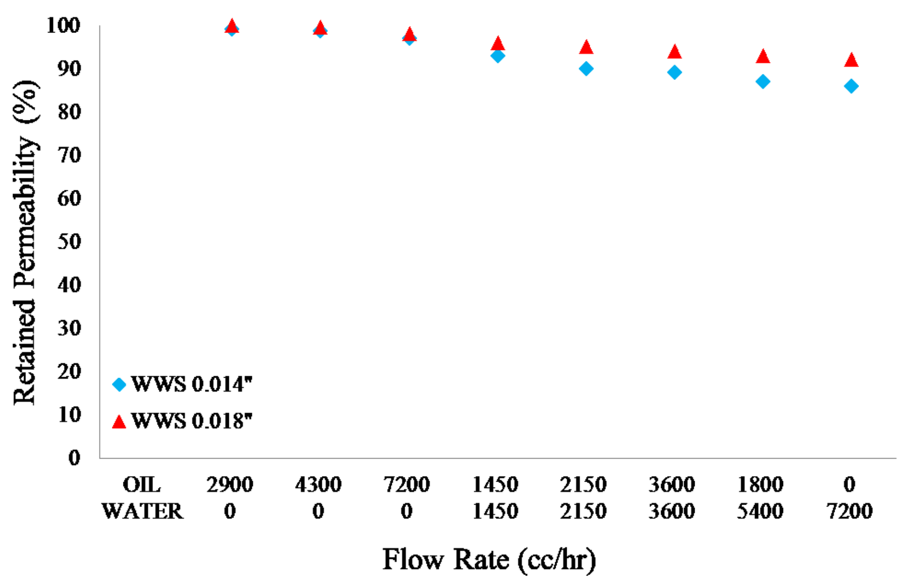

Fig. 14 Retained permeability values for WWS with the aperture sizes 0.014’’ and 0.018’’

In summary, obvious retained permeability reduction is observed after water breakthrough. Also, with the increase in water flow rate and water cut, a further decrease of retained permeability is found.

It is worth mentioning that proper SAS design for certain project could result in different SAS types with different aperture sizes. For instance, for a certain project, commonly higher aperture sizes are proposed for SL, in comparison to WWS and PS. Current experiments, have shown the capability of the experimental testing in determining the retained permeability for different SASs, under multi-phase condition. The provided experimental testing process could be followed to compare the SAS's with properly designed specifications considering the assumptions and limitations of the experiment.

5. Assumptions and Limitations

The proposed methodology could be used to characterize the pore plugging level for multi-phase flow sand control tests. However, there are a few assumptions and limitations in this methodology. First, the external saturation determination method only gives the average saturation. Therefore, the saturation distribution is assumed to be uniform along the sand-pack sample. Second, the capillary end effect in the near-screen section is neglected in the SRT tests. Third, the relative permeability curves are assumed as constant during the test. However, there could be some minor changes to the relative permeability values due to the fines migration. Fourth, these experiments focus on addressing the flow performance of stand-alone screens due to fines migration under short term condition. The aperture plugging phenomenon associated with corrosion, scaling, and temperature is not included and observed in these tests. Fifth, kaolinite and illite are the only clay type used in this study. However, there is some montmorillonite in the McMurray Formation. Sixth, steam is not included in the testing design. Thus, the impact of steam on fines migration is not investigated.

Overall, further study is recommended to 1) improve the saturation measurement method, 2) include temperature and corrosion effect into the testing design, 3) investigate the impact of clay type and clay diagenesis on fines migration, and 4) include steam in the testing.

6. Conclusions

This study proposes a methodology to characterize the formation damage in multi-phase sand control tests. Through the proposed methodology, one can quantitatively characterize the formation damage in the liner vicinity due to fines migration. Some key conclusions from this study are summarized as follows:

- The proposed methodology can be utilized in the sand control tests to analyze the flow performance of the screen.
- The new methodology can be applied in the sand control tests to characterize and quantify the pore plugging due to fines migration under multi-phase flow condition.
- Higher flow rates and water cut cause more elevated levels of fines migration.
- For the same aperture size, WWS shows the highest retained permeability compared to the PS and SL.
- All screens tested in this study show excellent and desirable flow performance.

The characterized screen flow performance of different screen types could be coupled with the sanding performance to obtain a more comprehensive assessment of the overall screen performance. Finally, the overall screen performance helps with the optimal selection of screen type for the SAGD projects.

Nomenclatures

q_w: water flow rate (cc/hr)

q_o: oil flow rate (cc/hr)

μ_w: water viscosity (cp)

μ_o: oil viscosity (cp)

A: area (in^2)

ΔP: pressure drop (psi)

k_{abs}: abosulte permeability (md)

k_{rw}: relative water permeability

k_{rw}: relative water permeability

k_{ro}: relative oil permeability

S_W : water saturation(%)

ρ_w: water density (g/cm^3)

V_{pore}: pore volume of the sand-pack sample (cm^3)

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