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EVALUATION OF CHEMICAL FOR SAND CONSOLIDATION IN LABORATORY SCALE

(Evaluasi Bahan Kimia untuk Konsolidasi Batuan Pasir pada Skala Laboratorium)

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ABSTRAK

Makalah ini berisi gambaran tentang percobaan laboratorium untuk mengevaluasi kenerja bahan kimia konsolidasi batu pasir menguatkan ikatan antar batir batuan sementara tidak menyebabkan penurunan permeabilitas yang signifikan. Percobaan ini menggunakan batuan dan fluida reservoar untuk mengetahui interaksi antara larutan kimia dengan batuan dan fluida reservoar. Pertama, batuan dan fluida reservoir dianalisis propertinya. Batuan tersebut telah dianalisis menggunakan CT Scan untuk mengebor core-plug yang mewakili eksperimen, menggunakan SEM untuk mengidentifikasi geometri leher pori dan pori batuan, menggunakan XRD untuk menentukan komposisi mineral dimana terdiri sebagian besar kuarsa. Sementara fluidanya telah dianalisis untuk kondungan anion dan kation, viskositas dan sifat penting lainnya. Kandungan partikel air formasi dan juga distribusi ukuran partikel batuan di overlay dalam grafik untuk mengetahui kemungkinan terjadinya partikel bridging di leher pori batuan, tetapi grafik terlihat baik bahwa tidak ada masalah yang mungkin timbul dari partikel bridging. Bahan kimia untuk konsolidasi pasir telah digunakan dalam percobaan ini. Bahan kimia untuk konsolidasi pasir biasanya mengandung resin plastik yang memiliki sifat dapat mengikat antar bahan padat. Bahan tersebut dapat menempel pada permukaan bahan padat dan mengikatnya. Percobaan core flooding telah dilakukan sebanyak 4 kali, 2 kali menggunakan batuan sintetis dan dua kali lainnya menggunakan batuaan inti asli. Percobaan menggunakan batuan sintetis menurunkan permeabilitas secara signifikan. Namun, setelah memotong kedua ujung batuan permeabilitas telah menunjukkan perbaikan kembali. 2 percobaan lainnya menggunakan batuan inti asli telah menurunkan harga permeabilitas sekitar 4 kali lebih kecil. Dua percobaan terakhir ini tidak dilakukan pemotongan ujung inti batuan ntuk percobaan lebih lanjut, sehingga tidak dapat dibandingkan dengan dua percobaan pertama. Jadi, prosedur percobaan harus diperbaiki untuk evaluasi berikutnya, seperti selama curing time laju injeksi minyak dapat dinaikkan untuk mengurangi adsorpsi kimia ke permukaan pori batuan dan juga untuk menghambat penggumpalan larutan kimia di pori pori batuan.

Kata Kunci*: *Bahan kimia-resin, problem pasir, kontrol pasir, konsolidasi pasir

ABSTRACT

These paper contains a highlight of laboratory experiment to evaluate the work of chemical for sand consolidation to strengthen the bonding between grains of rock while do not cause permeability reduction significantly. This experiment used reservoir rock and fluids to understand the interaction between the chemical solution and the reservoir rock and fluid. Firstly, the reservoir rock and fluid were analyzed their properties. The rock has been analyzed using CT Scan to drill the best representative core plug for the experiments, using SEM to identify the pore throat and pore geometry of the rock, using XRD to determine the minerals composition which mostly quartz. While the fluids have been analyzed for the anions and cations content, viscosity and other important properties. The brine particle content and also particle size distribution of the rock have been also over lied in the graph in order to know the possibility of bridging particle in the pore throat, but the graph looks good that no problem may arise from the bridging particle. Chemical for Sand Consolidation has been used in this experiment. Sand consolidation chemical normally contain plastic resin that has a property of bonding between solid materials. It sticks on the surface of solid materials and bonding together. The core flooding experiments have been run for 4 times, 2 times using synthetic cores and the other two using native cores. The experiments used synthetic cores reduce the permeability significantly. However, after cutting both ends of the core the permeability has indicated improvement. The other 2 experiments using native cores have reduced the permeability approximately 4 times down. The last two experiments have no cutting the ends of core for further experiments, so they cannot be compared to the first two experiment. So, the experiment procedures must be improved for the next evaluation, such as during curing time the rate of injected oil may be increased to reduce the adsorption of chemical to the surface area of the pore and also to hinder the flocculation of chemical in the pore space.

Keywords: Chemical-resin, sand problem, sand control, sand consolidation

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I. INTRODUCTION

During the lifetime of gas or oil fields, the reservoir formation experiences several conditions these may be susceptible to sand production. This severe condition may be happen normally due to: lose sand formation (unconsolidated sand), high production rate more than critical rate, high drawdown (high differential pressure), reduction of pore pressure when reservoir pressure depleted and undergo rock compaction, high reservoir fluid viscosity could create drag force to the sand grains, and increasing water production could develop sand production. Normally the reservoir fluid may flow easily when the reservoir has porous, permeable and well cemented together. However, in some cases the reservoir rocks consist of unconsolidated sand with very high permeability, when water break through to the production wells, this condition may be more susceptible to sand production (http://www.oilfield-wiki.com/wiki/Sand_control).

The production of sand can be severe damaging the well productivity and production facilities. The problems may arise include: sand accumulation in the down hole that can create productivity impairment, acumulation in surface equipment and trapped in the in the separator and production pipeline, erosion of down hole and surface equipment, collapse of the formation behind the casing. Therefore, if the formations have sand problems, they need sand handling to prevent more severe production and reservoir problems. Tibbles, et al. (2020) introduces several case studies of failures that occurred during sand control installations and details the investigative process and techniques used to identify the root causes. Examples include events such as screen/wash-pipe damage, bridging, hole collapse, and packer seal failure.

Sand problems can be detected prior before any production problem arise using several methods, including field observations, laboratory experiments, and theoretical models. For examples are for field observation includes sand flow test , Formation Strength Log, Sonic Log, Formation Properties Log, for laboratory experiment determines rock strength, and for theoretical model comprises Finite Element Analysis Model. Soroush, et al. (2020) provided some highlight to example of sand control potentials and application in Kazakhstan. Finally, a sand control design and evaluation protocol were provided based on the reviewed cases.

Managing the problem of sand production, there is a concept called sand control to cope the problem of sand and sand production. There many kinds of sand control technics, which consist of injection chemical-resin or silicon, screen with gravel pack, Slotted Liners or screen without Gravel Pack, and also some new Latest Technologies for sand control. Reyes, et al., (2018) gave an optimal sand control design & technique selection: a simplified practical guidance tool. List of criteria developed when contemplating sand control and completion method were as follows, 1. Determine the rock mechanics, 2. Study individual reservoir conditions, 3. Note lithological changes, 4. Obtain well data, 5. Characterize formation sand, 6. Select gravel size, 7. Select screen and size, 8. Select completion method and 9. Evaluate the potential cost and economical outcome.

Chemical-resin injection is simply a technology by injecting chemical-resin to the formation near well bore to form consolidated mass, binding sand grains together to increase in formation compressive strength. Epoxy resin had used for sand consolidation (Dewprashad, et al., 1977) at laboratory scale and field testing to consolidate sands and synthetic proppants. The new epoxy resin system has been successfully field-tested to provide proppant flowback control. Sand control in the field is challenging with high fines content in the reservoir, remedial sand control using chemical treatments that consolidate the near wellbore area can be a viable alternative to improve well offtake rates (Haavind, et al., 2008). Handil field had a sand problem near some well bores with gravel pack completion and they had been treated by sand consolidation chemical to improve the formation strength and enhance a maximum sand free rate (Mahardhini, et al., 2015). Gravel pack is commonly used as completion technique and also using resin sand consolidation (SCON) to overcome sand problem in Handil Field (Hadi, et al., 2019). The strategy to remedy the sand problem were to tested several types of chemical sand consolidation and choose the best fit and performance for matrix consolidation. A key learning is that adequate placement of the chemical is critical (Aytkhozhina, et al., 2015). Epoxy resin sealant also had been used to improve well integrity (Alkhamis, et al., 2019). This technic of epoxy resin injection will be investigated very detail in laboratory experiments to see the effect to the permeability.

II. METHODOLOGY

The sand consolidation experiment was performed using a core flooding equipment. Figure-1 shows the detail picture of this equipment (Sugihardjo, 2018). The rig consists of a 1.5-inch diameter of Hassler type core holder and core length can be inter-changeable among the three sizes such as: 3 inches, 1 foot, 1-meter long. In this experiment the three inches' core holder has been used. For the three inches' core holder are available 2 DPT (differential pressure transducer) measuring differential pressure of inlet and a port in the middle of the core and between inlet and outlet. The core holder was given an overburden pressure to keep the core tightly stick to the rubber sleeve. It was connected with three piston-equipped tubes, which contained the flooding

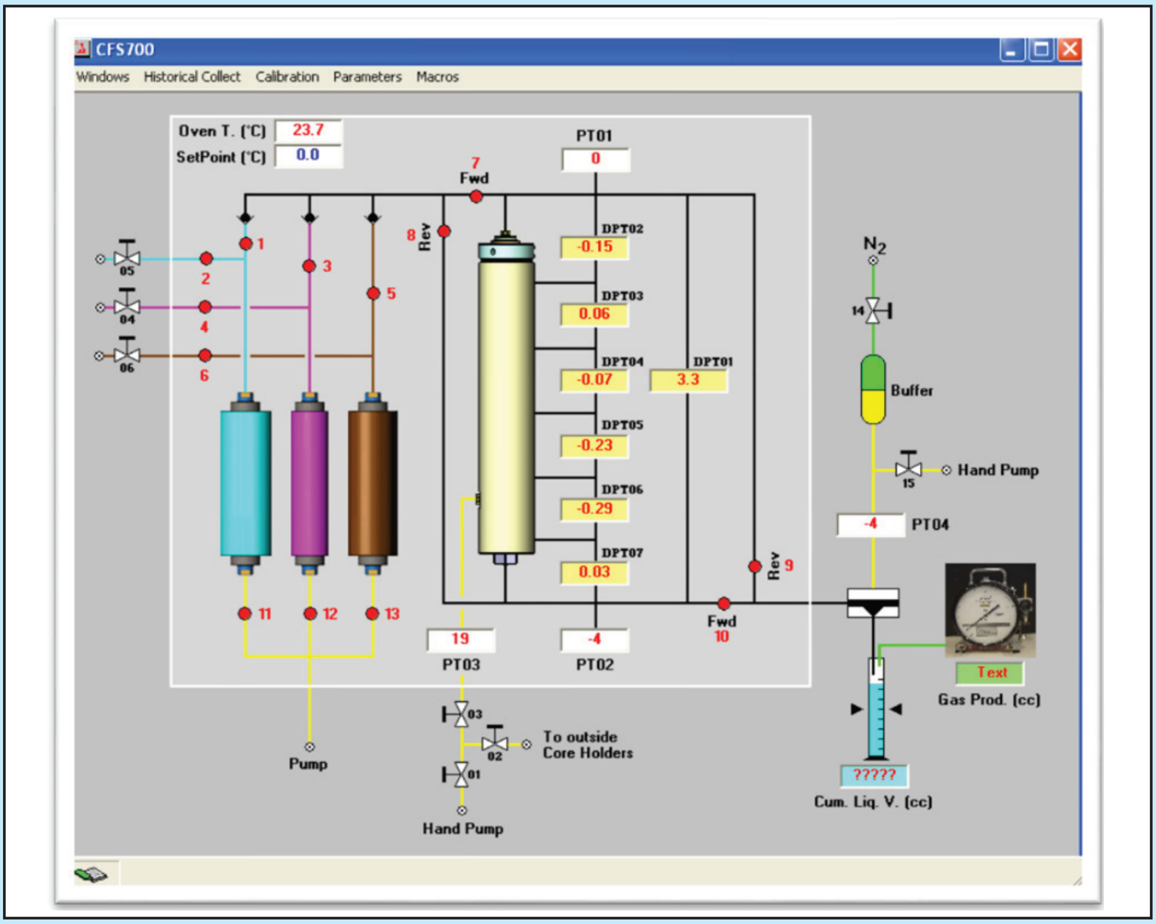

Figure 1
Lay out of the Sand Consolidation Apparatus

fluid, i.e. formation water, crude oil, and chemical solution. The tubes were provided with fluid regulating valves to enable the selection of fluid to flow into the core in the core holder.

A computer controlled quizix pump was used to force the injection fluid into the tubes. Besides that, a digital pressure indicator to control the flow of the fluid. In and out the core holder, it was also provided with a number of pressure transducers to observe the fluid movement in core and to observe the pressure difference in each segments of the core. In order to maintain a stable pressure in the core holder, it was equipped with a backpressure regulator. The fluid coming out of the core was directed to a separator and the liquid collected in a fraction collection so that both oil phase and water phase production can be measured as the function of time. The injection fluid taken, core holder, backpressure regulator and other accessories were placed in a circulation oven, which was equipped with temperature control. The system of pressure and temperature were detected at various locations by means of calibrated thermo-couples and transducers. The data collected during injection/flooding included pressure, flow rate, pressure difference, production and injection times were directly recorded in a computer. Those data, then has been evaluate to determine the range of permeability of the core, it means that the permeability improvement or impairment of the core can be defined straightly. Those properties of rock and fluid, then they can be compared to the original before chemical injection, and therefore they can be evaluated the degree of changes and of course the degree of damage or improvement. Moreover, in this experiment was focused on the measurement of permeability changes during chemical injection.

A. Materials

The experimental materials consist of reservoir brine, oil, and rock, also chemical solution. The properties of reservoir brine, oil, and rock are analyzed prior used to determine the ability of the chemical to consolidate the sand grains and without any negative effects such as permeability impairment and permeability blocking. The composition of brine is presented in Table 1, while the viscosity oil and water are presented in Table 2.

The other water properties were also measure, such as: TDS 3.35 ppt, Conductivity 9.93mS, Salinity 4.32 ppt, 3.98 Ω.

Before conducting measurement plugging, the cores were firstly examined using x-ray computed tomography scanner. The rock has also been analyzed using CT Scan to identify if there are any fractures and laminated. After scanning job of full diameter cores, the cores were plugged and the selected location based on the scanning determination that there were

Table 1
The result of brine analysis

Cation	mg/L
Na	1066.322
Ca	9.651
Mg	6.226
Fe	0.272
Ba	0.436
Sr	0.114
Anion	**mg/L**
Cl^-	313.42
OH^-	0
CO_3^-	0
HCO_3^-	2728.53
SO_4^{2-}	1

Table 2
Viscosity and density of brine and oil

Fluid Properties	Brine		Oil	
	@ room	@ 65ºC	@ room	@ 65ºC
Viscosity, m (gr/cc)	1.1035	0.6647	5.0335	4.887
Density, r (cp)	1.0251	1.0228	0.8485	0.8238

no fractures and more homogeneous. So only two core plugs were drilled for this experiment.

Besides, the core also evaluates by SEM to see visual pore-geometry, and the porosity. Figure 3 the result of SEM analysis. General SEM view shows pore-geometry of coarse but in some area is fine, angular to subrounded and moderately-poorly sorted grains. Framework grain components include mostly of quartz, feldspar, plagioclase and rock fragments. Mica slight present as accessory minerals. Matrix is minor amount, mainly composed of detrital clays such as kaolinite and illite. XRD was also performed to determine the mineralogy composition of the rock, and the result is exhibited in Table 3. The mineralogy mainly composes of quartz and also clay and a little carbonate. Next measurement is to determine the pore size distribution, which is over laid with particle size content in the brine. Figure 4 is the result of the overlay of both particle size and pore size. Pore throat size distribution provides evidence that pore aperture diameter of below 0.1mm is 5.4%, 0.1-1.0mm about 13%, 1-10mm around 25%, 10-30mm around 39%, and above 30mm approximately 5%. Compare these values to particle size content in produced water to anticipate any bridging formation during water injection. Last rock properties measurement is porosity and permeability of the core plug. Table 4 is the result of basic data measurement. The synthetic cores only after first experiment were cut both end and measure the rock properties ones more, see Table 5.

B. Chemical Solution

The chemical used in this experiment is chemical type for sand consolidation (Magee, 2014). This chemical is designed for consolidation treatments in unconsolidated formations. Objective of the tests is to evaluate the damage or improvement of the permeability of the core after injected some this chemical solution. Core flooding experiments were performed to analysis the damage or improvement of those parameters after some this chemical solution with concentration of 7% was injected into the core. After that the permeability or injectivity was

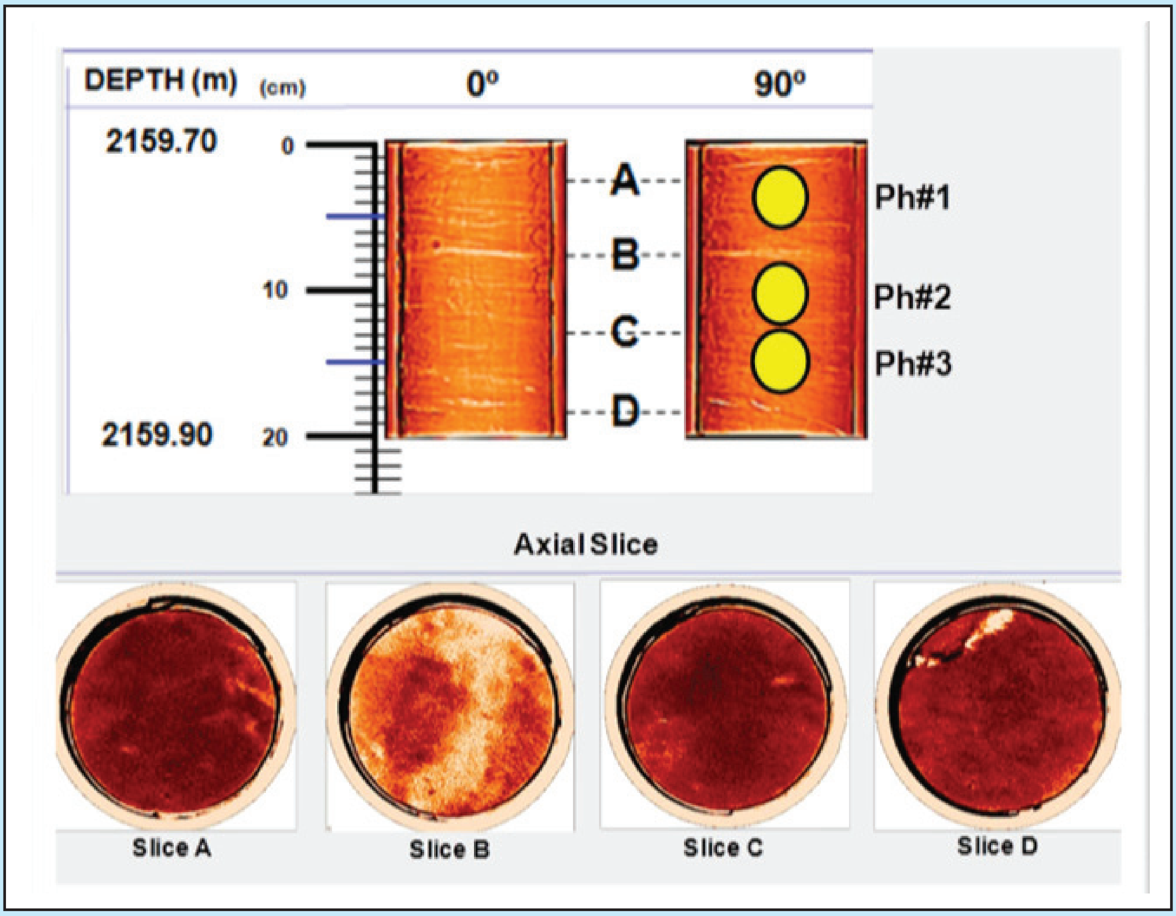

Figure 2
The result of scanning for core plugging.

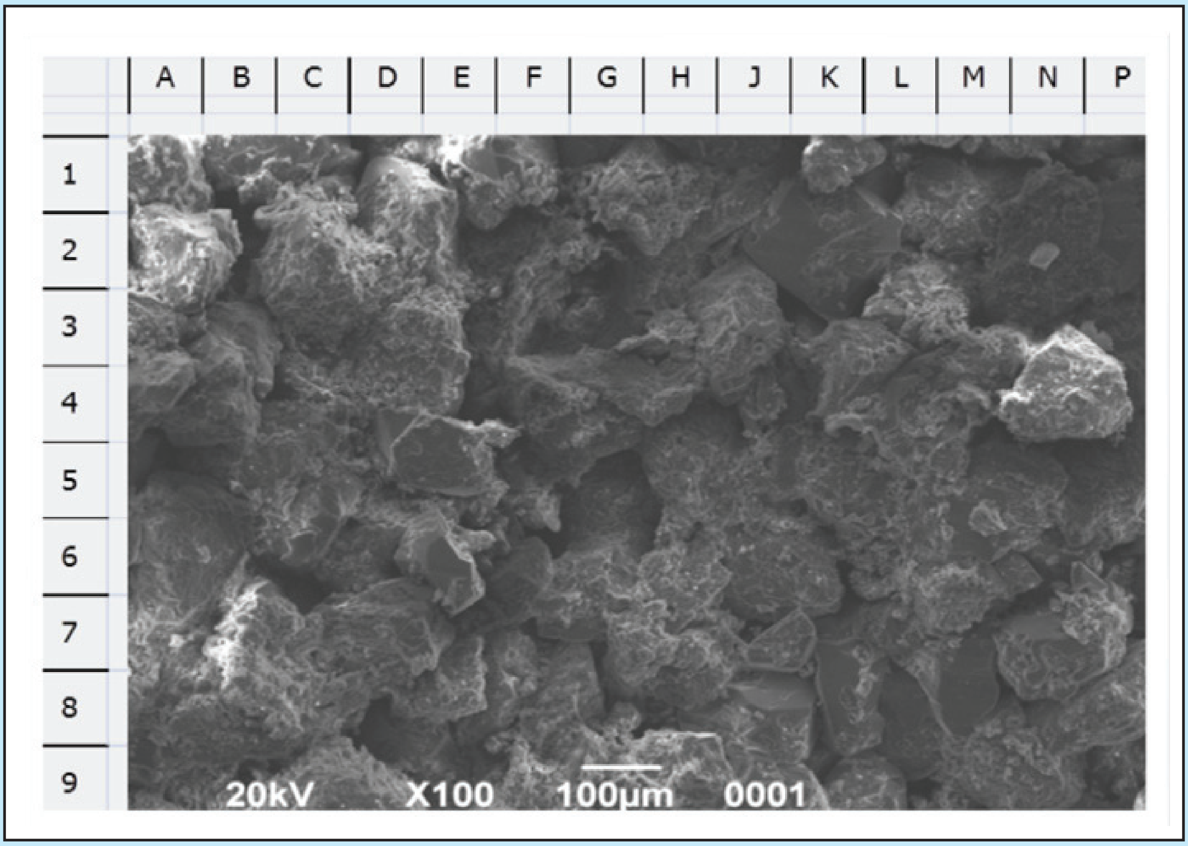

Figure 3
The result of SEM analysis.

Table 3
The result of XRD Analysis

No.	Sample	Clay Minerals (%)				Carbonate Minerals (%)			Other Minerals (%)					Total (%)		
		Smectite	Illite	Kaolinite	Chlorite	Calcite	Dolomite	Siderite	Quartz	K-Feldspar	Plagioclase	Pyrite	Gypsum	Clay	Carbonate	Other
1	Sample-1	-	3	8	-	-	-	3	82	-	2	1	1	11	3	86
2	Sample-2	-	3	7	-	-	-	3	84	-	2	-	1	10	3	87

measured and compared to the original permeability to determine the final chemical treatment effect. The properties of the chemical solution especially viscosity is shown in Table 5. Illustration of the work of the chemical to consolidate the grains of rock is presented in Figure 5. The chemical solution displaces and replace Swi layer and strengthen bonding between rock grains.

C. Experimental Procedure

This test was done using four core samples, two synthetic cores and the other two native core samples. The tests are to study the effect on chemical injection to change of the permeability of the cores, improvement or damage of the original permeability. The procedure of the tests is mentioned in the following paragraphs:

Table 4
Core plugs basic data

Core Sample	Length (cm)	Diameter (cm)	Section Area (cm^2)	Bulk Volume (cm^3)	Dry Weight (gr)	Wetted Weight (gr)	PV (cc)	POR (%)	Kair (mD)	Core Type
Plug-1	7.4	3.755	11.08	81.98	169.54	187.16	17.19	20.966	300	Synthetic
Plug-2	7.4	3.743	11.01	81.46	169.46	187.17	17.28	21.208	300	Synthetic
Plug-3	6.975	3.724	10.9	76	133.21	161.56	27.65	36.387	5546	Native
Plug-4	7.422	3.716	10.85	80.53	141.78	171.33	28.83	35.796	5525	Native

Table 5
Basic synthetic core data after cutting

Core-ID	Length (cm)	Diameter (cm)	Section Area (cm^2)	Bulk Volume (cm^3)	POR (%)	Kair (mD)	Core Type
Plug-1	3.871	3.755	11.08	42.89	17.188	300	Synthetic
Plug-2	4.585	3.743	11.01	50.47	17.276	300	Synthetic

1. Weight the dry core and record the weight
2. Put the core in the bottle and vacuum for a day and then saturated fully with formation brine
3. Weight the core at wet condition and calculated the pore volume
4. Insert the brine saturated core into core holder, put in the oven and apply a confining pressure
5. Start brine injection, apply several decreasing flow rates and at stabilized pressure values measure pressure drop to calculate initial permeability values of Kw initial at Sw=1
6. Displace brine with oil until getting stabilized pressure drop (minimum 6 PV)
7. Heat the core holder to reservoir temperature (65°C) similar to the reservoir temperature and maintain the confining pressure
8. Continue oil injection and apply several decreasing flow rates. At stabilized pressure values measure pressure drop to calculate initial permeability values of Ko initial at Swi (In Injection way)
9. Inject oil (minimum 2 PV) at rate 0.23 cc/sec
10. Inject chemical with concentration of 7% diluted diesel oil approximately 2 PV at the injection rate of 0.23 cc/sec
11. Unplug inlet & outlet line to/from core, unplug chemical line, flushing with oil and purging to prevent plugging at inner line
12.`Then, close the cell inlet and outlet and start the curing time (12 hours). Continue pumping oil at very low injection rate (0.01 cc/minor minimum rate) to minimize plugging risk on the line (in production way)
13. After the curing time, start oil injection, apply several increasing flow rates and at stabilized pressure values measure pressure drop to calculate final permeability values of Ko1 final at Swi
14. Unplug outlet line from core (production way), flushing with oil & purging to cleaning line from chemical solution. This procedure to minimize plugging effect at downstream line during calculating final Ko2@Swi
15. Calculate regained permeability values for each applied flow rate
16. Cool down the core holder, release the pressure and open the cell
17. For the synthetic cores only: take out the core from the core holder
18. Cut the core of both ends to see if there are any permeability improvement
19. Measure the core length
20. Reload in the core holder and set back the core flooding system to the original (pressure and temperature)

21. Continue to inject oil for around 2 PV and measure the permeability Ko2@ Swi
22. End Of testing - unload the core
23. Clean the pistons of the cell and check any presence of hard deposits in the valves and tubing, in case of evidence of plugging of pistons fluid path, it could be interesting to repeat the final permeability measurements.

D. Applied Equation

The recorded data from core flooding experiments consist of rate, inlet and outlet pressure (differential pressure) as the function of time. Combining those data with the basic core data can be employed to calculate the permeability, permeability reduction, and Injectivity index. Three equations have been formulated to calculate those three parameters, and write down in the following formulas:

Initial and final permeability:

$$k(mD) = 1.0103 * 10^6 * \frac{\mu * L}{S} * \frac{Q}{\Delta P}$$

With:

K in mDarcy (mD)

μ: fluid viscosity at test temperature (cP)

L: Length of core plug (cm)

S: Section area of core plug (cm^2)

Table 6
Chemical solution properties

Chemical Properties	7% chemical Concentration @ 65ºC
Viscosity, m (gr/cc)	4.887
Density, r (cp)	0.8238

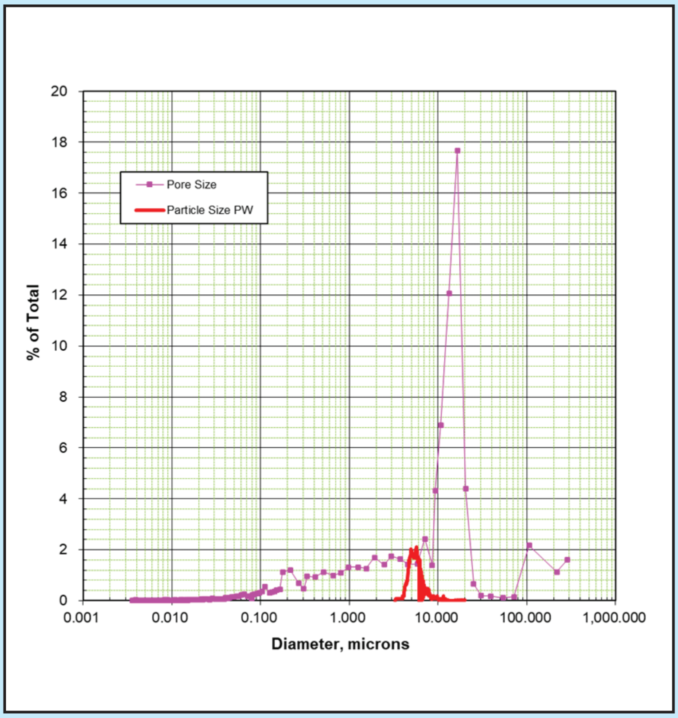

Figure 4
Overlay of pore and particle size distribution of the core and produced water.

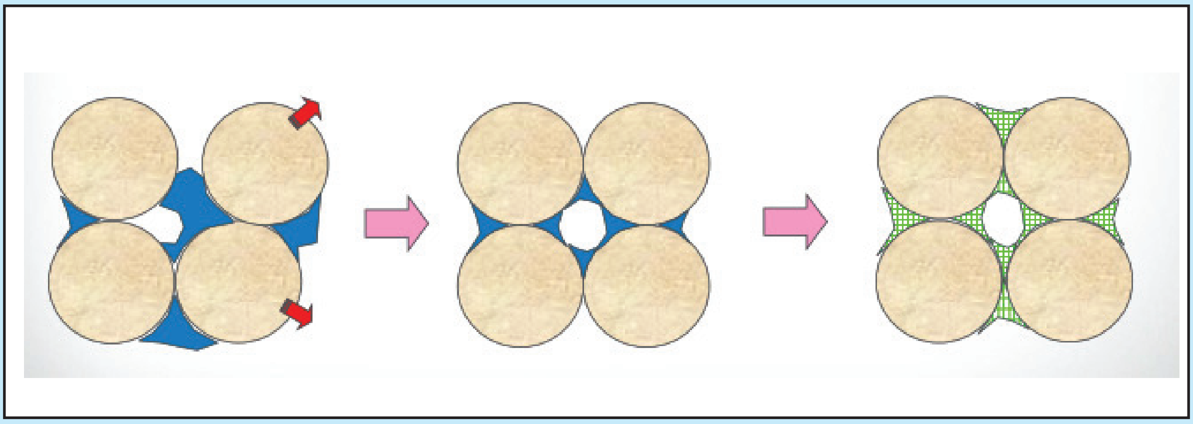

Figure 5
The processes of rock grains bonding.

Q: fluid flow rate (cm^3/s)

ΔP: Pressure Drop through Core plug (mbar)

Reduction permeability:

$$RP(\%) = \left[\frac{Kf}{Ki}\right] * 100\%$$

With:

RP: Reduction permeability (%)

Ki and Kf: Initial and final permeability (mD)

Injectivity Index of Sand Consolidation Chemical treatment:

$$\text{Injectivity index} = \frac{\left[{}^{Q\ initial}/_{\Delta P\ initial}\right]}{\left[{}^{Qm}/_{\Delta Pm}\right]}$$

With:

Q initial: Flow rate for initial oil injection

ΔP initial: Pressure drop for initial oil injection

Qm: Measured flow rate after Sand Consolidation Chemical treatment

ΔPm : Measured pressure drop after Sand Consolidation Chemical treatment

E. Core Flooding Injection Design

The summary of the core flooding injection design is figured out in Table 6. This Table contents fluid injected, concentration, rate, temperature, and remarks.

III. RESULTS AND DISCUSSION

The sand consolidation tests have been done twice for synthetic core samples which include cutting ends core plugs for final core flood tests. While the additional injectivity tests of the two native core

Table 7
Fluid injection design

No.	Fluid	Rate	Temp.	Remarks
1	Brine injection	varied (1-11cc/min)	ambient	Injection more than >10 PV until injection pressure stable and measure Kw
2	Oil injection	varied (1-7cc/min)	room	Displace Brine with oil >6PV and maintain stable pressure
	Heating of the core flood system to reservoir temperature of 65ºC until stable			
3	Cont' oil injection	13.8 cc/min	65ºC	2 PV Flushing oil and measure Ko@Swi
	Injected Chemical solution and curing time			
5	Injected chemical solution 7%	0.01 cc/min	65ºC	2 PV of Sand Consolidation Chemical
6	Oil injection (reverse flow)	0.01 cc/min	65ºC	Minimum 12 hours Curing time
	Injection After Curing Time			
7	Oil injection (reverse flow)	varied (1-7cc/min)	65ºC	When pressure is stable then measure Ko1@Swi
8	Cont' oil Injection (reverse flow)	varied (1-8cc/min)	65ºC	Flushing oil more than >6 PV After stable pressure measure Ko2@Swi
	Unload core- cut both ends-reload core			
9	Cont' oil injection	varied (1-7cc/min)	65ºC	2 PV injection and measure Ko3@Swi

Table 8a
The results of consolidation test of synthetic core of plug-1

Fluid Injected	Q (cc/s)	ΔP (bar)	K(mD)	RP (%)	Injectivity Index
Brine (Kw)	0.117	0.772	122.6		
	0.1	0.683	118.885		
	0.083	0.586	115.388		
Oil (Ko@Swi)	0.017	0.31	193.054		
	0.025	0.4	224.674		
	0.033	0.49	244.716		
	0.017	0.283	211.888		
	0.033	0.462	259.326		
	0.05	0.648	277.258		
Oil Ko1 @ Swi after 7% of Chemical Injection	0.05	3.661	49.081	21.846	4.578
	0.033	2.406	49.785	22.159	4.513
	0.017	1.069	56.048	24.946	4.009
	0.017	1.241	48.263	21.481	4.655
	0.033	2.441	49.081	21.846	4.578
Oil Ko2 @ Swi after Flushing > 6PV	0.05	3.537	50.804	22.612	4.422
	0.033	2.406	49.785	22.159	4.513
	0.025	1.696	52.972	23.577	4.241
	0.017	1.027	58.305	25.951	3.853
After Ends of Core Cut					
Oil Ko3 @ Swi	0.1	1.076	174.787	77.796	
	0.083	0.91	172.138	76.618	
	0.067	0.745	168.313	74.915	

plugs without cutting ends core and directly finished. The data of both type of core is presented in Table 2 and Table 3 for after cutting.

1. First experiment was run using a synthetic core of Plug-1 for consolidation tests, and the result is shown in Table 7. The average initial permeability to oil at Swi (Ko@Swi) is around 224.67 mD. After Chemical injection, the permeability decreases down to RP average 22.48% this number indicates severe permeability damage. After injected more than 6PV of oil the RP value do not return to the original or improvement, the RP average is still around 23.90%. Injectivity index has an average value around 4.374 indicated that more than 4 times permeability reduction. However after ends cut the RP average value improves significantly to about 76.44%. This may be indicated that the damage only occurs in both tips of the core. But It will be compared with other next injectivity tests results in order to draw the right conclusion.
2. Second experiment was still performed using a synthetic core of Plug-2. The result of the test is written down in Table 8. The result is also revealing the permeability reduction at the end of experiment turn into an average of RP about 72.80% or 1.37 Injectivity index. However, after cutting both of core tips, regained permeability occurs during flooding to about 117.51%. From both experiments can be withdrawn a temporary conclusion that permeability reduction is much severe in the ends of the core, but the magnitude of the permeability reduction is not conclusive yet.

Table 8b
The Results of Injectivity Test of Synthetic Core of Plug-2

Fluid Injected	Q (cc/s)	∆P (bar)	K(mD)	RP (%)	Injectivity Index
Brine (Kw)	0.117	0.814	117.16		
	0.083	0.572	118.975		
	0.067	0.462	117.91		
	0.067	0.462	117.91		
	0.05	0.352	116.176		
	0.033	0.248	109.722		
Oil (Ko@Swi)	0.083	1.4	215.437		
	0.067	1.165	207.023		
	0.05	0.965	187.43		
	0.05	0.965	187.43		
	0.042	0.855	176.345		
	0.033	0.738	163.49		
Oil Ko1@ Swi after 7% of Chemical Injection	0.133	2.951	163.49	87.227	1.146
	0.117	2.751	153.451	81.871	1.221
	0.1	2.317	156.191	83.333	1.2
	0.05	1.22	148.25	79.096	1.264
	0.042	1.02	147.749	78.829	1.269
	0.033	0.827	145.779	77.778	1.286
Oil Ko2@Swi after Flushing > 6PV	0.05	1.296	139.575	74.468	1.343
	0.042	1.089	138.398	73.84	1.354
	0.033	0.869	138.837	74.074	1.35
	0.133	3.51	137.473	73.346	1.363
	0.117	3.13	134.861	71.953	1.39
	0.1	2.793	129.581	69.136	1.446
After Ends of Core Cut					
Oil Ko3@Swi	0.1	0.99	225.81	120.48	
	0.08	0.85	220.3	117.54	
	0.07	0.7	214.63	114.51	

3. The next experiment was performed with a native core of Plug-3. The injection processes are similar to the previous experiment the difference is only without cutting the tips of the core at the end of experiment. The result is exposed in Table 8, an average RP value at the final injection is approximately 23.31% or 4.3 of injectivity index, that means the permeability reduction more than 4 times, and it could not be recovered after more than 6PV injection.
4. The last experiment was performed also using native core Plug-4. The injection processes is similar to the third experiment. Table 8 shows the experimental result. The average value of RP at the end of experiment is around 21.45% or about 4.67 injectivity index.

IV. CONCLUSIONS

Chemical used for sand consolidation normally contain plastic resin that has a property of bonding between solid materials. It sticks on the surface of solid material and bonding together. While the solid materials compose of rock grains. Based of the data of X-ray and SEM, the rock composes dominantly by quartz with granular grain size. So, injection chemical sand consolidation could be appropriate for this sand problem in field scale.

Table 8c
The Results of Injectivity Test of Native Core Plug-3

Fluid Injected	Q (cc/s)	∆P (atm)	K(mD)	RP (%)	Injectivity Index
Brine (Kw)	0.183	0.103	1379.11		
	0.15	0.083	1410.454		
	0.117	0.069	1316.423		
	0.117	0.069	1316.423		
	0.083	0.055	1175.378		
	0.067	0.041	1253.737		
Oil (Ko@Swi)	0.1	0.09	3844.024		
	0.083	0.076	3785.781		
	0.067	0.062	3701.653		
	0.05	0.048	3569.451		
	0.067	0.062	3701.653		
	0.083	0.076	3785.781		
Oil Ko1@Swi after 7% of Chemical Injection	0.1	0.359	961.006	25.962	3.852
	0.083	0.29	991.514	26.786	3.733
	0.067	0.221	1041.09	28.125	3.556
Oil Ko2@Swi after Flushing > 6PV	0.083	0.317	905.296	24.457	4.089
	0.1	0.4	861.592	23.276	4.296
	0.117	0.49	821.141	22.183	4.508

Table 8d
The Results of Injectivity Test of Native Core Plug-4

Fluid Injected	Q (cc/s)	∆P (atm)	K(mD)	RP (%)	Injectivity Index
Brine (Kw)	0.067	0.055	1004.875		
	0.033	0.034	803.9		
	0.017	0.021	669.917		
Oil (Ko@Swi)	0.1	0.138	2670.202		
	0.083	0.117	2617.845		
	0.067	0.097	2543.05		
	0.067	0.097	2543.05		
	0.05	0.076	2427.456		
	0.033	0.055	2225.168		
Oil Ko1@Swi after 7% of Chemical Injection	0.083	0.869	353.201	13.889	7.2
	0.067	0.655	374.765	14.737	6.786
	0.05	0.462	398.538	15.672	6.381
Oil Ko2@Swi after Flushing > 6PV	0.033	0.234	523.569	20.588	4.857
	0.025	0.165	556.292	21.875	4.571
	0.017	0.11	556.292	21.875	4.571

From 4 experiments on synthetic and native cores can be withdrawn a conclusion that the injection of Chemical Consolidated Sand could reduce the permeability more than 4 times of down to below 25%. Cutting the tips of the core after injected of 6PV oil may improve the permeability. So, the more severe permeability damage may occur in the both ends of the core.

It is suggested to reduce the effect of injected chemical on the permeability of core, during curing time the rate of injected oil should be increase a little bit to 0.1 cc/minute (2.75ft/day in the field is similar to 0.1 cc/minute in the lab.) to reduce the adsorption of chemical to the surface area of the pore and also to hinder the flocculation of chemical in the pore space.

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