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Investigation of in-situ low-temperature oxidation as a viable sand consolidation technique

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Abstract

This paper presents the results of the laboratory development phase of a major project to develop a novel sand control technique that could overcome the technical and economic limitations associated with existing methods of sand control. The novel technique is based on in-situ sand consolidation by low-temperature oxidation of a hydrocarbon material that saturates the sand around the wellbore. Laboratory development consisted of two stages. In the first stage, the various process-controlling parameters were optimized to yield consolidated sand with the highest possible compressive strength, minimum loss of permeability, and high stability against typical formation and workover fluids. Under the optimum consolidation conditions, it was possible to produce consolidated sand, from originally loose sand, that is completely stable against flow of crude oil, water and mud acid; has a compressive strength between 1800 and 2300 psi; and with permeability retention between 86.4% and 95.5%. In the second stage, the feasibility of field application of the process was demonstrated on a full-scale physical model resembling an 8-ft section of a 7-in. cased well. The model was packed with loose sand and saturated with crude oil and residual brine. The resulting consolidated sand around the casing was tested by flowing back at a rate of 44 bpd/ft (the maximum available pump capacity) without any sand production. Plans are underway for the first field implementation of the process.

Keywords: Sand production; Sand control; Sand consolidation; Low-temperature oxidation; Permeability retention

1. Introduction

Sand production is normally encountered when oil, gas and water are produced from unconsolidated or weakly consolidated sandstone reservoirs. Sand production could also occur for consolidated sandstone reservoirs when the production rate (or pressure drawdown) exceeds what is known as the critical production rate (or critical drawdown). Sand production is one of the most serious problems encountered in the petroleum industry. Without proper measures to control or eliminate sand production, frequent washout operations and replacement of surface and subsurface equipment will be necessary, which significantly increases production costs.

Sand production could be eliminated by producing the well below its critical rate. This, however, will be uneconomical for most fields. Existing methods of sand control, such as gravel packing and plastic consolidation, have been in use for many years with varying degrees of success. There are, however, several well-known technical and economic limitations associated with these methods. Even when successfully implemented, these methods cause sig-

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nificant reduction in the near-wellbore permeability and loss of productivity. In addition, these methods do not present a permanent solution and requires frequent repairs. Frac and Pack is another more recent technique that has been used for sand control. However, its application is still limited and its cost is believed to be high. It is, therefore, evident that a new method of sand control that could overcome the technical and/or economic limitations of the existing methods would be desired.

Several investigators have proposed in-situ sand consolidation techniques utilizing oxidation of hydrocarbons. In these techniques, the oxidation reaction is employed to produce a coke-like solid residue that bonds the sand grains together. Oxidation may be carried out in conjunction with forward combustion (Marx, 1964; Terwilliger and Goodwin, 1966; Push, 1975), reverse combustion (Smith, 1965; Reed, 1965, Chaney and Watson, 1965), or low-temperature oxidation (Terwilliger and Goodwin, 1966; O'Brien, 1966; Redford, 1976). The hydrocarbons can be the native crude oil (Smith, 1965; Engles and Santourian, 1968) or introduced as a slug of bitumen (O'Brien, 1966), an autoignitable or cokable liquid (Smith, 1965; Engles and Santourian, 1968), or a carbohydrate (O'Brien, 1966). The reaction temperature for the low-temperature oxidation (LTO) based techniques ranged between 205 and 315 °C, while for the other techniques, reaction temperatures in excess of 315 °C were reported. Most of the reported methods used very heavy oils or bitumen as the consolidating fluid and employed relatively high oxidation temperatures, which limits the applicability of such methods in the field. A novel method of sand consolidation, employing lower oxidation temperatures and lighter oils, as the consolidating liquid, has been recently proposed (Osman et al., 2000). This method demonstrated the potential of the LTO process, under more favorable conditions compared to the previously reported work, in producing consolidated sand that possesses high compressive strength, excellent stability against formation and workover fluids with minimal loss of permeability.

Based on the results of this novel method, a major two-phase project was initiated to further develop the consolidation process and implement it in the field. The first phase of the project, which is the subject of the present paper, dealt with the laboratory development of the process. The process-controlling parameters have been optimized for application in two major Saudi Arabian fields. One of these fields produces Super Light oil, while the other produces Arabian Heavy oil. Further, the feasibility of field application has been demonstrated using a full-scale wellbore model resembling actual completions in these fields. Based on the encouraging results of this work, plans are under way for field implementation of this novel method, which has already been patented (Aggour et al., 2002).

2. Process optimization study

The objective of this study was to determine the optimum process conditions to produce consolidated sand with the highest possible compressive strength, good stability against typical formation and workover fluids, with minimum loss of permeability. To achieve this objective, an experimental investigation was conducted where various potential consolidating fluids and oxidation temperatures were employed to consolidate loose sand packs, resembling the actual reservoirs' sand, under actual reservoir pressure conditions. The resulting consolidated sands were tested for its permeability retention, compressive strength and stability against flow of oil, water and mud acid. The effect of the presence of clays in the sand on the quality of consolidation was also examined.

2.1. Experimental setup

A simplified schematic of the process optimization experimental setup is shown in Fig. 1. Four specially designed core holders were used to house the sand packs and provide confining and pore pressures. Means were provided to automatically control and maintain these pressures constant throughout the experiment. The core holders were housed, vertically oriented, inside a temperature-controlled oven. Valves and by-pass systems were provided to interchange the flow through the core holder between the upward and downward directions. Separate pumps were used for saturating the sand packs with brine and crude oil, and for injection of the consolidating liquid. Air compressor and a

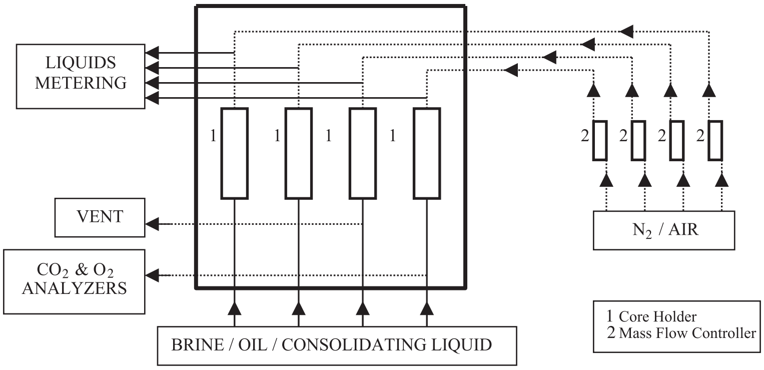

Fig. 1. Schematic of process optimization setup.

pressure multiplier system were used to provide the high-pressure air that was used as the oxidizing medium. The setup was equipped with instrumentation for measuring the confining pressure, pore pressure, differential pressure, temperature, and liquid and gas flow rates. CO_2 and O_2 analyzers were used to measure the CO_2 and O_2 contents in the effluent gas stream. All measurements were continuously recorded on the data acquisition and control computer. A software package was prepared for the dynamic graphical display of all process variables and measurements, and for performing necessary computations.

2.2. Materials

Loose sand from an outcrop in Saudi Arabia that was found to closely match the grain size distribution and mineralogy of one of the two reservoirs under consideration was used in one set of the experiments. In the other set of experiments, sand from actual cores obtained from the second reservoir formation was used. Six liquids were tested for use as a consolidating fluid. These were: Arabian Heavy Crude oil from one of the field under consideration, aged samples from the same crude oil, a refinery heavy residue obtained from the vacuum column bottom stock, and asphalt-reformate solutions of 40%, 60%, and 80% asphalt concentrations. Air was used as the oxidizing agent. Crude oils from the two fields and synthetic brines resembling formation waters were used to saturate the sand packs prior to the consolidation process.

2.3. Experimental procedures

2.3.1. Sand packs preparation and saturation

Two different sizes of sand packs were used in the experiments; these were: 1 and 2 in. diameters with a length of 2 and 4 in., respectively. For each experiment, four sand packs were prepared; care was taken to have the four packs as identical as possible. The packs were then loaded into the core holders inside the oven. The confining pressure was then applied and maintained at a constant value (500 psi above the pore pressure) and the oven temperature was set at the desired value. Vacuum was then applied to remove air from the sand packs. With the backpressure set at the desired pore pressure, each sand pack was first flushed with several pore volumes of preheated brine, and then with the preheated crude oil until residual water saturation is achieved. The flow of brine and oil was in the upward direction. This brought the sand pack to initial reservoir conditions. During

Table 1
Experimental results for fluid #1, sand #1

Run #	D × L (in.)	OT (°C)	BP (psi)	PR (%)	Compressive strength (psi)		
					Original	After acid treatment	After O/W treatment
8	2 × 4	100	2500	93.8	1321	1352	1289
9	2 × 4	150	2500	94.2	1520	1520	1573
24	1 × 2	100	50	93.6	1258	1344	1195
25	1 × 2	150	50	92.8	1448	1325	1520

D × L: Sand pack diameter × length, OT: Oxidation temperature, BP: Back pressure, PR: Permeability retention.

Table 2
Experimental results for fluid #2, sand #1

Run #	D × L (in.)	OT (°C)	BP (psi)	PR (%)	Compressive strength (psi)		
					Original	After acid treatment	After O/W treatment
10	2 × 4	100	2500	93.3	1020	968	948
12	2 × 4	150	2500	92.7	1305	1156	1195
27	1 × 2	100	50	88.3	982	827	850
28	1 × 2	150	50	92.8	1260	1080	1180

D × L: Sand pack diameter × length, OT: Oxidation temperature, BP: Back pressure, PR: Permeability retention.

this process, measurements were taken to evaluate the porosity, permeability, and fluids saturations of the sand pack.

2.3.2. Oxidation (consolidation) procedure

With the sand packs maintained at the corresponding reservoir pore- and confining pressure and the desired oxidation temperature, the consolidating liquid was injected into each sand pack to displace the oil in place and saturate the sand pack with the consolidating fluid. Nitrogen gas was then injected into the sand pack, in the downward direction, to reduce the saturation of the consolidating fluid down to the residual saturation. This was then followed by air injection, at a controlled rate, to oxidize the consolidating fluid remaining in the sand. The effluent air was analyzed for its CO_2 and O_2 contents. During this process, measurements were taken to determine the residual saturation of the consolidating fluid, and all process parameters such as air flow rate, sand-pack temperature, CO_2 and O_2 concentrations were recorded and graphically displayed versus time. The process was terminated when the O_2 concentration in the effluent air remained unchanged (and equal to the inlet concentration), thus signaling the completion of the oxidation process.

2.3.3. Evaluation of consolidated sand

The four (nearly) identical sand-pack samples produced from the oxidation process were used to evaluate the quality of consolidation achieved. One sample was used for permeability measurements to determine the loss in permeability due to consolidation. The second sample was used to determine the compressive strength of the consolidated sand. The third sample was subjected to a flow of over 1000 pore volumes of mud acid (3% HF, 12% HCl) and the effluent was checked for sand production. The sample was then soaked in the mud acid for one week. Then, it was dried and its compressive strength was measured and compared against that of the second (untreated) sample. The fourth sample was subjected to repeated flow of brine and oil totaling over 4000 pore volumes at a differential pressure of 100 psi and the effluent was checked for sand production. The sample was then cleaned and dried, and its compressive strength was measured and compared against that of the second (untreated) pack.

2.3.4. Experimental conditions

The major variable in the present study was the type of consolidating fluid. Six different liquids were used. These were: (1) fresh crude oil obtained from one of the two field under consideration, (2) an aged sample of the same crude oil (*Fluid #1*), (3) a refinery heavy residue obtained from the vacuum column bottom stock (*Fluid #2*), (4) a 40% asphalt-in-reformate solution (*Fluid #3*), (5) a 60% asphalt-in-reformate solution (*Fluid #4*), and (6) an 80%

Table 3
Experimental results for fluid #3, sand #1

Run #	D × L (in.)	Sand composition	OT (°C)	BP (psi)	PR (%)	Compressive strength (psi)		
						Original	After acid treatment	After O/W treatment
13	2 × 4	pure silica	100	2500	94.8	1674	1628	1691
16	2 × 4	pure Silica	150	2500	96.0	1902	1895	1918
29	1 × 2	pure silica	100	50	94.2	1638	1718	1695
31	1 × 2	pure silica	150	50	95.5	1864	1855	1809
32	1 × 2	+ 4% clay	100	50	86.4	2347	2314	2405
33	1 × 2	+ 4% clay	150	50	87.2	2618	NA	NA

D × L: Sand pack diameter × length, OT: Oxidation temperature, BP: Back pressure, PR: Permeability retention.

Table 4
Experimental results for fluid #4, sand #1

Run #	D × L (in.)	Sand composition	OT (°C)	BP (psi)	PR (%)	Compressive strength, psi		
						Original	After acid treatment	After O/W treatment
17	2 × 4	pure silica	100	2500	93.8	1675	1598	1289
20	2 × 4	pure silica	150	2500	95.2	1820	1784	1573
34	1 × 2	pure silica	100	50	93.1	1536	1592	1195
35	1 × 2	pure silica	150	50	94.3	1773	1620	1520
39	1 × 2	+ 4% clay	100	50	86.1	2218	2230	1195
40	1 × 2	+ 4% clay	150	50	86.5	2436	NA	NA

D × L: Sand pack diameter × length, OT: Oxidation temperature, BP: Back pressure, PR: Permeability retention.

asphalt-in-reformate solution (*Fluid #5*). Oxidation was performed at two different temperatures: 100 and 150 °C for all consolidating liquids. Two different sands were tested; one was obtained from a sand outcrop resembling the formation sand of one of the two fields (*Sand #1*), and the other was from actual cores obtained from the second field (*Sand #2*). The effect of the presence of clay on the quality of consolidation was tested by adding 4% (by weight) of Kaolinite to sand samples consolidated at 100 °C and employing Fluid #3, Fluid #4, and Fluid #5 as consolidating liquids.

2.4. Results and discussion

Oxidation experiments conducted on *Sand #1* using the fresh crude oil (Arabian Heavy Crude) as a consolidating fluid, at 100 and 150 °C yielded inadequate consolidation. Therefore, the results of these experiments are not discussed here. The results of the experiments employing the other five consolidating liquids and using *Sand #1* are summarized in Tables 1–5. Because of the limited availability of *Sand #2*, only two consolidation experiments were performed using *Fluid #3* at oxidation temperatures of 100 and 150 °C. The results for these two experiments are shown in Table 6. Fig. 2 compares the permeability retention (i.e., the permeability of the consolidated sand as a percentage of the permeability of the sand pack before consolidation) obtained with the five consolidating fluids at oxidation temperatures of 100 and 150 °C for clean *Sand #1*, i.e., *Sand #1* without clay. The effect of mud-acid treatment on the compressive strength, C_o, of the consolidated sand for the five consolidating fluids and the two oxidation temperatures is illustrated in Fig. 3. Similarly, the effect of formation oil and water on consolidation stability (compressive strength) is illustrated in Fig. 4. The effect of the presence of clay in the sand on permeability retention for the two oxidation temperatures is illustrated in Fig. 5. Similarly, the effect of clay on consolidated sand compressive strength is shown in Fig. 6. Figs. 7 and 8, respectively, show the effect of mud-acid treatment, and formation oil and water on consolidation stability with the presence of clay in the sand.

Table 5
Experimental results for fluid #5, sand #1

Run #	D × L (in.)	Sand composition	OT (°C)	BP (psi)	PR (%)	Compressive strength (psi)		
						Original	After acid treatment	After O/W treatment
21	2 × 4	pure silica	100	2500	92.4	1702	1736	21
23	2 × 4	pure silica	150	2500	95.3	1865	1812	23
41	1 × 2	pure silica	100	50	91.7	1520	1395	41
42	1 × 2	pure silica	150	50	93.6	1768	1792	42
44	1 × 2	+ 4% clay	100	50	84.7	2184	2150	44
46	1 × 2	+ 4% clay	150	50	85.3	2387	NA	46

D × L: Sand pack diameter x length, OT: Oxidation temperature, BP: Back pressure, PR: Permeability retention.

Table 6
Experimental results for fluid #3, sand #2

Run #	D × L (in.)	OT (°C)	BP (psi)	PR (%)	Compressive strength (psi)		
					Original	After acid treatment	After O/W treatment
47	1 × 2	100	50	93.8	1321	1352	1289
48	1 × 2	150	50	92.8	1448	1325	1520

D × L: Sand pack diameter × length, OT: Oxidation temperature, BP: Back pressure, PR: Permeability retention.

In the following subsections, the present results are discussed in terms of the effects of the main process variables (consolidating fluid, oxidation temperature, and presence of clay) on permeability retention, compressive strength and consolidation stability against acid and formation fluids.

2.4.1. Effect of consolidating fluid on permeability retention

As shown in Fig. 2, all five consolidating fluids used resulted in high retention of permeability. *Fluid #3* (40% Asphalt in reformate solution) produced the highest permeability retention (94.2% at 100 °C and 95.5% at 150 °C), while the lowest permeability retention, 88.3% at 100 °C, was associated with *Fluid #2* (refinery heavy residue). These values are significantly higher than those obtained with existing plastic consolidation (26–73%). This indicates the superiority of the present method in this regard.

2.4.2. Effect of consolidating fluid on compressive strength

As shown in Tables 1–5 and Figs. 3 and 4, the highest compressive strength was obtained with *Fluid #3* as the consolidating fluid (1864 psi at 150 °C and 1638 at 100 °C), while the lowest compressive strength, 982 psi, was obtained with the refinery heavy residue at 100 °C. Such values of compressive strength are considerably high specially, with the consolidation process being employed on originally loose sand. With these values of compressive strength, the consolidated sand could withstand very high pressure-drawdown without failure.

2.4.3. Effect of consolidating fluid on consolidation stability

As mentioned earlier, the stability of the consolidated sand was tested in two ways: mud-acid treat-

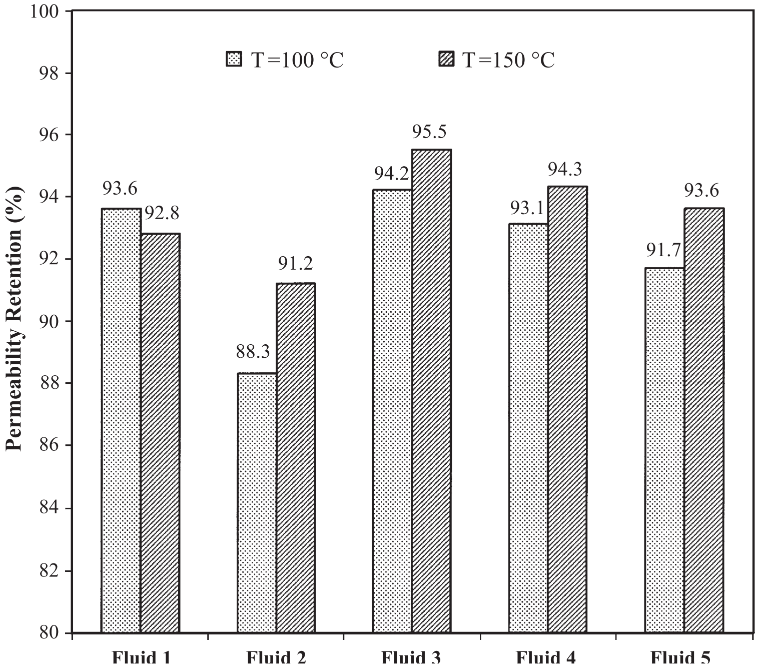

Fig. 2. Permeability retention at 100 and 150 °C oxidation temperatures.

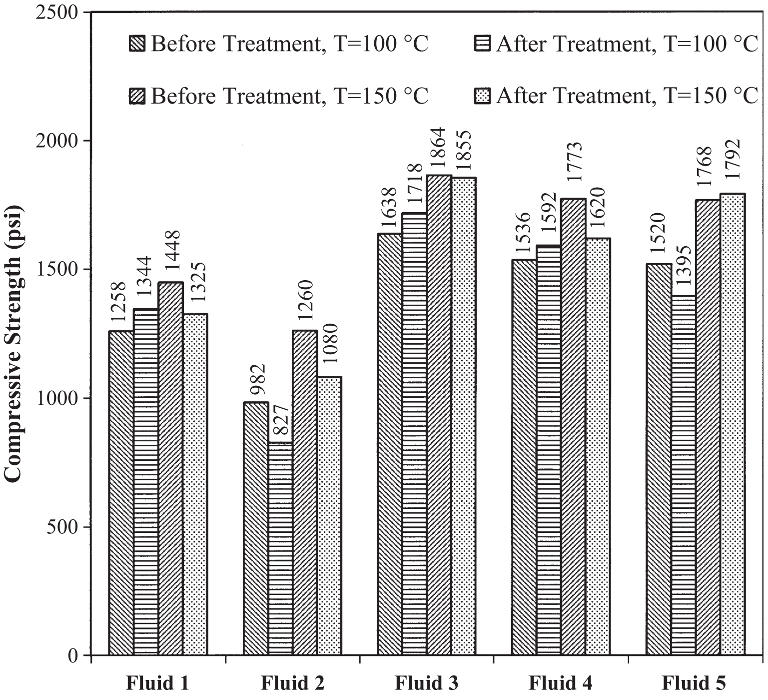

Fig. 3. Effect of mud-acid treatment on compressive strength.

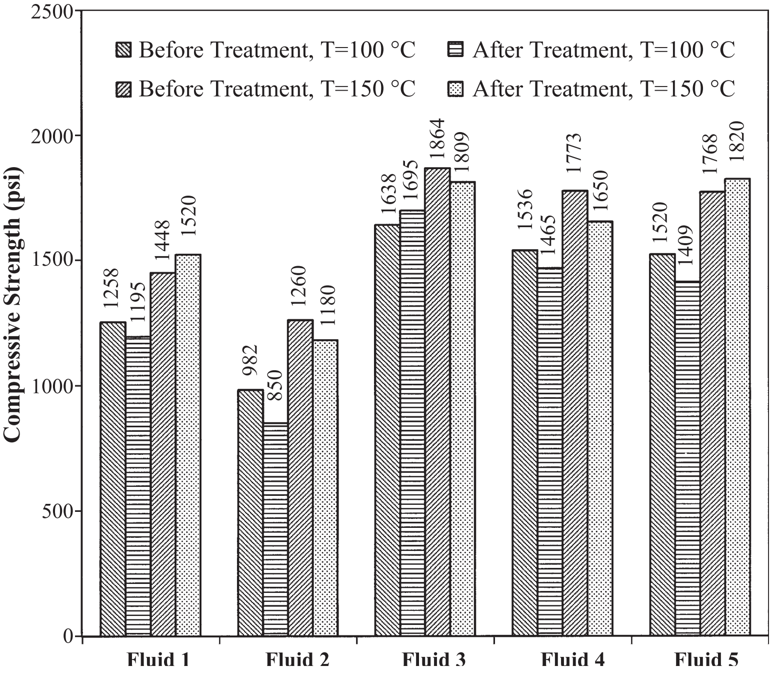

Fig. 4. Effect of formation fluids on consolidation stability (compressive strength).

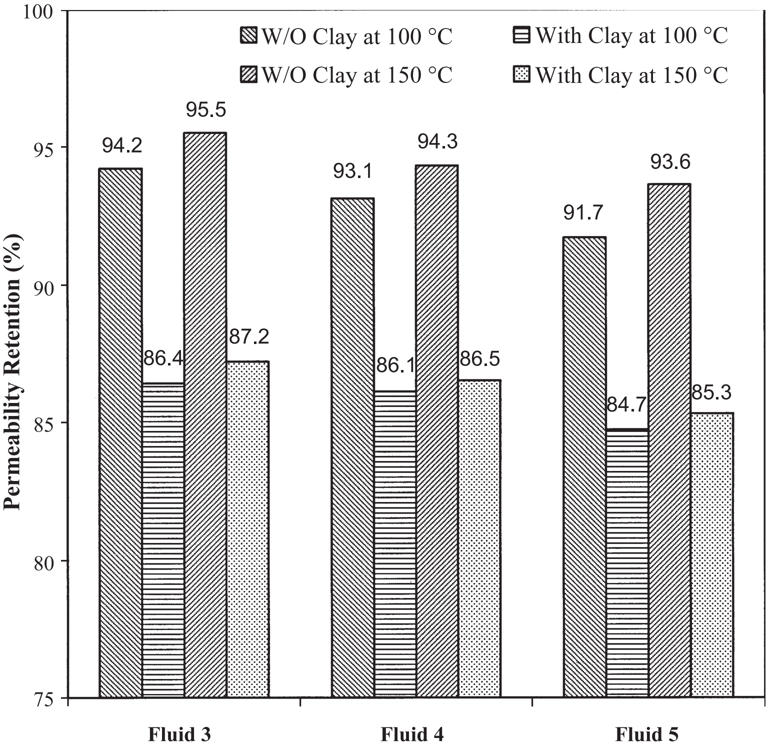

Fig. 5. Effect of clay on permeability retention.

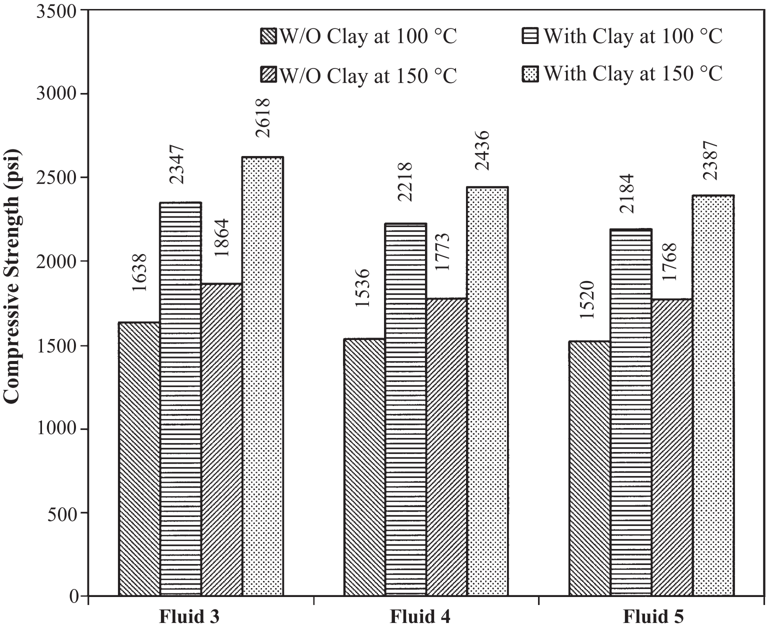

Fig. 6. Effect of clay on compressive strength.

ment and formation-fluids treatment. No sand production was observed during either of the two treatments for all consolidated samples; except the samples consolidated by the refinery heavy residue where some sand was produced during the first few minutes of flow. The measured values of the post-treatment compressive strength (Tables 1–5 and Figs. 3 and 4) did not exhibit a specific trend when compared to the pre-treatment values of compressive strength. With the exception of the samples consolidated by the refinery heavy residue (which produced some sand during the initial flow period), the differences between the pre-and post-treatment values of compressive strength for each consolidating fluid were well within the experimental errors. It could be concluded, therefore, that for all consolidating fluids, except the refinery heavy residue, the resulting consolidated sand is stable against flow of mud acid and formation fluids. The refinery heavy residue appears to be the least desirable out of the five tested fluids.

2.4.4. Effect of oxidation temperature on permeability

Two oxidation temperatures, 100 and 150 °C, were tested in the present study. Investigation of Tables 1–5 and Fig. 2 shows that the higher oxidation temperature generally results in higher permeability retention. The increase in permeability retention with temperature is rather small and could be due to experimental errors. In fact, and according to the kinetics of the LTO reaction, it is expected that the main contribution of the higher temperature to the process would be the acceleration of the reaction.

2.4.5. Effect of temperature on compressive strength

The data presented in Tables 1–5 and reproduced in Figs. 3 and 4 shows that the higher oxidation temperature consistently resulted in higher compressive strength. This is probably because the oxidation at higher temperature resulted in further drying and curing of the consolidating film and, thus, giving it higher strength since all samples were oxidized for the same duration.

2.4.6. Effect of temperature on consolidation stability

The data presented in Figs. 3 and 4 clearly shows that, with the exception of the samples consolidated with the refinery heavy residue, the consolidated samples were equally stable at both oxidation temperatures.

2.4.7. Effect of clay on permeability

Fig. 5 compares the degree of permeability retention for the sand containing clay against that for the pure sand for the two oxidation temperatures. The results clearly show that the presence of clay resulted in significant reduction in permeability retention. This is readily explained by realizing that the fine clay particles provided additional surface area for the deposition of the consolidating material, thus creating restrictions to the flow of fluid through the consolidated sample.

2.4.8. Effect of clay on compressive strength

Investigation of Fig. 6 shows that the presence of clay in the sand resulted in significant increase in compressive strength as compared to the compressive strength of the consolidated pure sand. A compressive strength as high as 2600 psi was obtained with *Fluid #3* as the consolidating liquid and oxidation temperature of 150 °C. At 100 °C oxidation temperature, the compressive strength was above 2300 psi. The clay particles, which are dispersed within the sand pack, provided additional surface area for the deposition of the consolidating material. This, in turn, provided additional bonding points and, thus, better cementing and higher compressive strength.

2.4.9. Effect of clay on consolidation stability

Stability tests, as described before, were performed on the sand-clay packs consolidated at 100 °C. Again no sand was produced while flowing acid or formation fluids through the consolidated samples. The pre- and post-treatments values of compressive strength, compared in Figs. 7 and 8, show that the presence of clay did not affect the consolidation stability against acid and formation fluids.

2.4.10. Optimum consolidation conditions

From the results and discussion presented above, the best consolidation was obtained with *Fluid #3* (40% Asphalt in reformate solution) as the consolidating liquid and 150 °C as the oxidation temperature. However, oxidation temperature of 100 °C is recommended. This is because: (1) there were only small differences between the values of compressive strength and permeability retention obtained with oxidation temperature of 150 °C and those obtained with oxidation temperature of 100 °C, (2) one of the fields

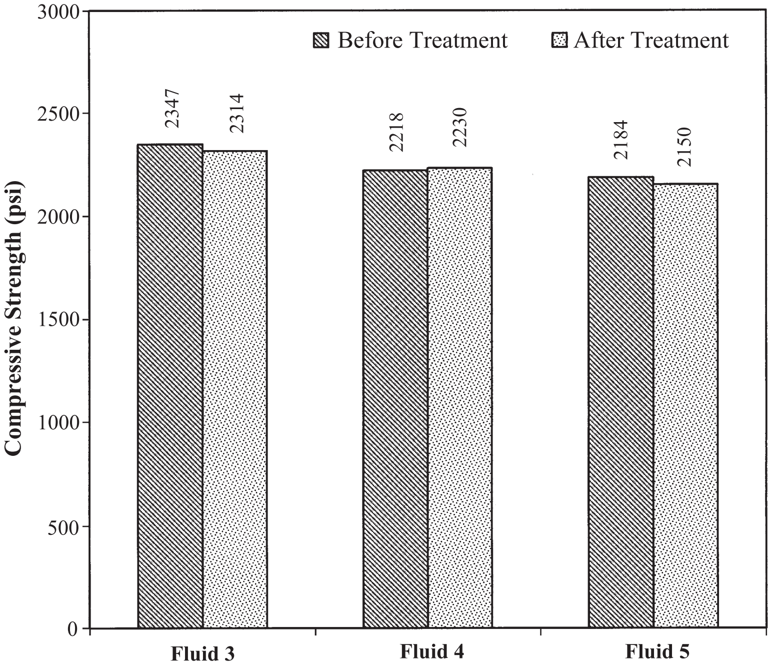

Fig. 7. Effect of clay on consolidation stability against acid.

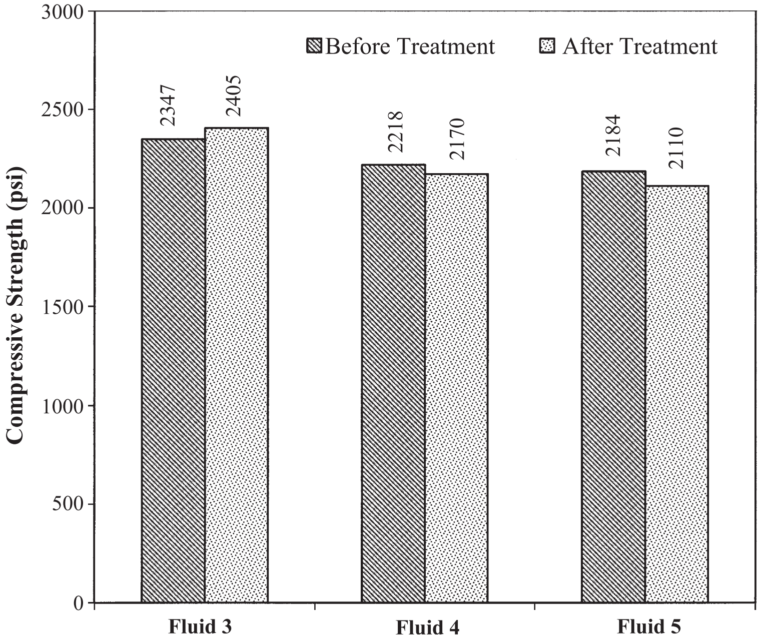

Fig. 8. Effect of clay on consolidation stability against formation fluids.

considered for application of the present process has a reservoir temperature close to 100 °C, and (3) consolidation at 100 °C would require less heating of the near-wellbore formation, consolidating liquid, and oxidizing air, which would reduce the cost of the process.

3. Wellbore-model demonstration study

As mentioned earlier, one of the objectives of the present work was to investigate the feasibility of field application of the novel consolidation process. For this purpose, a full-scale wellbore model, representing an 8-foot thick horizontal slice of a vertical 7 in. cased well and its immediate vicinity, was fabricated along with the necessary associated experimental facilities. The model was used to test the present consolidation method. Following is a description of the experimental setup, procedures, and results.

3.1. Experimental setup and materials

A simplified schematic of the wellbore-model is shown in Fig. 9. The model consists of a 7 in. diameter, 8 ft long casing, which is surrounded by a sand pack held in place by a 2 ft diameter pipe (the sand retainer). A 4 ft diameter pipe serves as the model's outside body. The casing has four, 0.5 in. perforations per foot, which are all connected by tubing to a common manifold. This casing manifold is used for air injection as well as production of fluids from the sand pack. Thermo-wells protrude from the casing into the sand pack at different heights; these wells house thermocouples to monitor the sand pack temperature throughout the experiment.

The casing manifold is connected to a small two-phase, gas–liquid separator equipped with a back-pressure regulator. Gas effluent from the separator is passed through a condenser before it is emitted to the exhaust. A small portion of the gas effluent is routed through an acid scrubber, a dryer, and finally an oxygen analyzer for measuring the O_2 content of the gas. A schematic of the wellbore model setup is shown in Fig. 10.

The sand retainer is perforated with five rows of small holes, each row having nine holes equally spaced along the perimeter. The holes are covered by a mesh screen to prevent sand movement out of the retainer. Ports with manifolds are provided to deliver or remove liquids from the annular space between the retainer and model body. These production manifolds are connected to a water–oil separator.

The entire model body is housed inside a heating jacket within which heating oil is circulated around the model and through the casing and heated by electric heaters.

Air is supplied to the model by an air compressor with pressure regulator and flow meter. The air supply line is first routed through the heating jacket to preheat the air to the sand-pack temperature.

The same materials as described in Section 2.2, except that only one type of sand, the loose sand from the outcrop, was used in these experiments.

3.2. Experimental procedure

With the model partially assembled, the space between the casing and sand retainer was packed with loose clean sand. A wet-packing procedure was followed to ensure adequate packing of the sand. The model was then completely assembled. The heating jacket's heaters and pump were then turned on to raise the model's temperature to the desired level, a process which took about 8 h. To speed up the heating process and to ensure even temperature distribution, hot brine was circulated through the sand pack itself by injection through the casing manifold. The brine flowed through the sand pack, out through the sand retainer holes, and out of the model through the production manifold. This step also served as the initial brine saturation stage of the sand pack.

When the sand pack temperature reached about 100 °C, hot brine circulation was stopped and brine was drained from the sand pack. The consolidating fluid was then circulated through the sand pack through the casing manifold-similar to brine circulation step. Several pore volumes of the consolidating fluid were circulated to ensure complete wetting of the sand. The sand pack was then drained of the consolidating fluid. Air injection was then begun to start the oxidation stage of the experiment. Once again, air entered the sand pack through the casing perforations and exited through the retainer holes to simulate radial flow. During oxidation, the production separator was drained periodically of any fluids that accumulate such as brine and excess consolidating fluid. Air

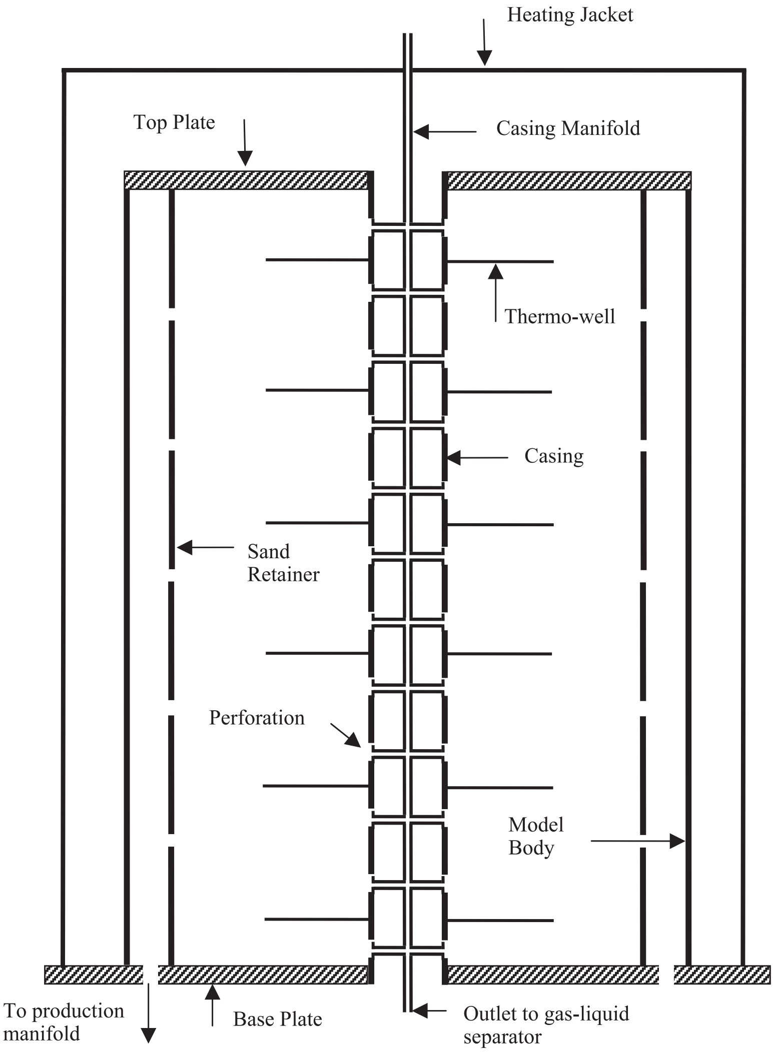

Fig. 9. Schematic of well-bore model.

injection continued until the oxygen concentration in the effluent gas remained unchanged and equal to that of air for a sufficiently long period of time. This signaled completion of the oxidation (consolidation) process. The resulting consolidated sand was then tested by flowing brine and/or oil through the model. The test fluid was injected through the production manifold, entered the sand pack through the retainer holes, flowed towards the casing, and exited the pack via the casing perforations. In other words, the flow is opposite to that of brine or consolidating fluid during initial saturation or air flow during oxidation. During backflow, the produced fluid was checked continuously for sand production. Heating was then stopped and the model was left to cool down. The model was then drained and disassembled for further testing of the consolidated sand.

3.3. Results and discussion

A total of seven runs were conducted on the well-bore model. In the first six runs, different procedures for saturation of the sand pack and air injection and production, and different consolidating liquids were

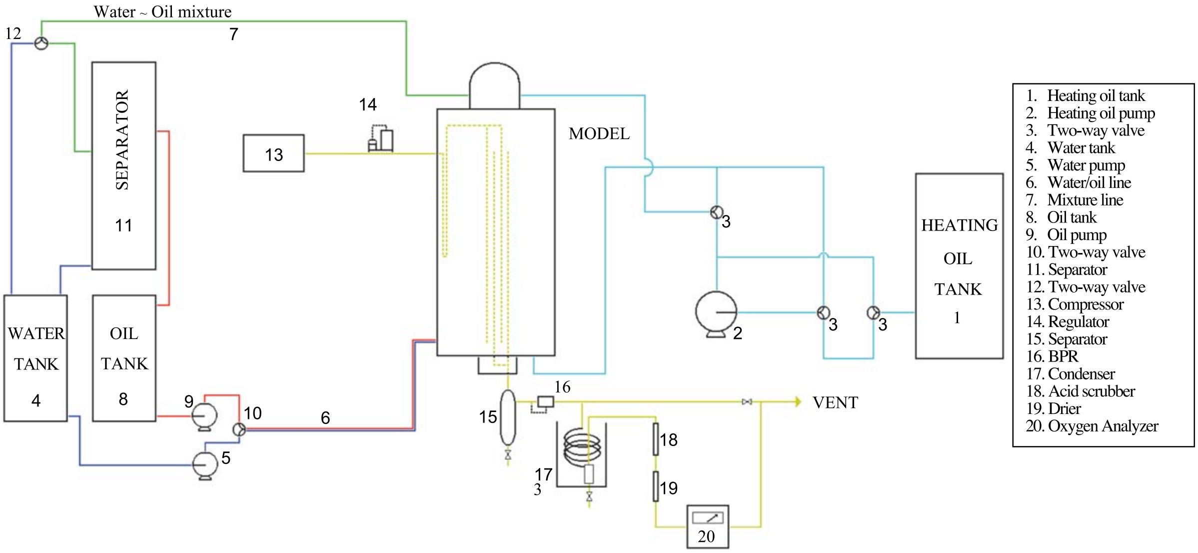

Fig. 10. Schematic of well-bore model experimental setup.

tested. At the conclusions of these runs, some modifications to the model were implemented and the best mode of air injection was determined. Also, the process optimization study was completed and the best consolidation conditions were determined. Therefore, the last (7th) run was conducted with the model and procedure described above and with *Fluid #3* (40% Asphalt in reformate solution) as the consolidating liquid. The sand pack properties and operating conditions for this run are summarized in Table 7.

Following the completion of the consolidation process, brine was pumped into the model, entering through the retainer perforations and produced from the casing perforations, at a gradually increasing rate until the available pump capacity was reached. This was equivalent to a production rate of 44 bpd/ft. For the field under consideration, this represented a production rate of 8800 bpd. No sand production was observed indicating that the sand was well consolidated.

Disassembling the model required lifting the retainer to expose the consolidated sand for visual observation. However, that was not possible because the sand pack was so consolidated that it was cemented to both casing and retainer. Instead of lifting the retainer loose, the sand pack and the whole assembly, weighing over 5000 pounds, was lifted off the ground with the retainer. The casing, the retainer and the consolidated sand in between were, then, separated from the rest of the system. A section of the retainer was cut off and removed exposing a solid, well-consolidated block of sand.

Cores were taken from the resulting consolidated sand and were tested for permeability, compressive strength, and stability in the same manner followed in the process optimization study. Similar results as those of the optimization study were obtained. A sample of the consolidated sand has been soaked in mud acid since November 1997 with no signs of deterioration.

The results obtained successfully demonstrated the feasibility of employing the present consolidation method in situations similar to those encountered in the field.

4. Conclusions

- In-situ low-temperature oxidation (LTO) of hydrocarbon substances saturating a sand matrix has been shown to produce a consolidated permeable sand body.
- The type of hydrocarbon substance used as the consolidating medium greatly affected the permeability and compressive strength of the resulting consolidated sand.
- For a given consolidating medium, higher oxidation temperature increased the compressive

Table 7
Sand pack properties and operating conditions—run #7

Bulk volume (l)	562
Pore volume (l)	214
Porosity (%)	38.1
S_w (%)	23.6
S_o (%)	31.4
Temperature (°C)	100
Consolidation fluid	*reformate/asphalt*
Air injection rate:	
(std. l/min.)	50
(MCFD)	2.5
Air outlet pressure (psi g)	0
Pressure drop across pack (psi)	2
Injection interval	all perforations
Production interval	entire sand pack
Air injection time (h)	93

strength of the consolidated sand but did not affect its permeability.

- The presence of clay in the sand resulted in significant increase in the compressive strength of the consolidated sand accompanied by a reduction in its permeability.
- A novel method of sand consolidation based on LTO of a hydrocarbon substance has been developed and the optimum consolidation conditions have been determined in the laboratory.
- Under the determined optimum conditions, the resulting consolidated sand had a compressive strength in excess if 1800 psi, retained 95.5% of its original permeability and was stable against flow of mud acid and formation fluids.
- The process has been successfully demonstrated on a full-scale wellbore model resembling actual wells. The success of this demonstration indicated the feasibility of field application of the new process.
- Plans are underway for the first field implementation of the new process. The engineering design and field preparation have been completed and field implementation and evaluation are expected to be completed early 2003.

Nomenclature

BP	Backpressure, psi
C_o	Compressive strength, psi
S_w	Water saturation, %
S_o	Oil saturation, %
T	Temperature, °C

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