



Review Paper

Chemical treatment for sand production control: A review of materials, methods, and field operations



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ABSTRACT

Sand production from loosely consolidated reservoirs is one of the critical issues in the oil and gas industry all around the world that can cause many problems, such as erosion of surface and well equipment, sand accumulation in wells and operation facilities, buckling of casing in cased-hole wells and well productivity reduction. Sand production control methods include restrictive production rate, mechanical methods (slotted liner, wire-wrapped screen, pre-packed screen, frac-pack, gravel pack, high-rate water pack) and chemical consolidation that chemical method is considered for more effectiveness in sand production alleviation due to increasing formation strength in near wellbore region. This review provides an overview on the laboratory and field operation investigations of chemical remedy for sand production. Some used chemical agents and more common laboratory tests for evaluating the chemical performance in sand consolidation are introduced in this paper. Furthermore, the results of field operations and injections of chemicals into the desired formation are also reported. These results show that the chemical sand consolidation is more effective in newly perforated wells which have no sand production experience and have a production history of less than two years. Finally, it was concluded that the main challenges in applying this method are permeability and capillary force reduction around the wellbore and selective injection into the targeted formation layers.

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1. Introduction

Nowadays, by production amplification of oil and gas reservoirs in the world, operational problems such as water production, sand production and production reduction due to aging of the reservoirs will arise that sand production is one of the major problems which the oil industry has faced in recent decades. A substantial percentage of the oil and gas reservoirs have unconsolidated (weak) sandstone formation that the most important drawback of such reservoirs is sand production.

Sand production can cause many problems. Well productivity can diminish because of wellbore failure (sand fill up). Also, disposal of produced sand is a remarkable cost operation and has the environmental effects (Rahmati et al., 2013). Moreover, loss of

production time, erosion in bottom hole tubular, safety valves, chokes and bottom hole equipment, sand accumulation in surface lines and equipment, buckling of casing, plugging the perforations, well-bore instability, failure of sand control completions, collapse of some sections of a horizontal well in unconsolidated formations and additional cost of remedial and clean-up operations are the inevitable obstacle of sand production (Rahmati et al., 2013; Vardoulakis et al., 1996).

The main reasons for sand production are the numerous drilling and production operations (Inappropriate operations might result in sand production. Under pressure drilling in unconsolidated formations and improper production operations like cement job, perforation, and increasing the rate of production can lead to sand production), reservoir *in-situ* stress state and rock deformation, level of pressure drop around the wellbore and reservoir depletion which all of them cause to sanding by removing the cement between the sand grains (Araujo Guerrero et al., 2014). In drilling and

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well completion operations, invasion of drilling and completion fluids into the formation will cause changes such as clay swelling, wettability alteration of reservoir rock and emulsion formation around the well (Wang et al., 2005). Also, various operations, including drilling, well completion, and production, can generate the stress in near wellbore region and disrupt the equilibrium of stresses on the reservoir rock. By applying stress into the formation, the cementation between sand grains is eliminated and the reservoir rock will have sand production potential. Furthermore, as production begins from the reservoir, a pressure drop will gradually occur around the production well which is proportional to the flow rate. If the production flow rate is too high, there will be a severe pressure-drop in near wellbore region and because of the disruption of the stress equilibrium, the reservoir rock strength will be lost and sand production potential increases. Moreover, effective stresses will increase because of the constant overburden pressure and decreasing of average reservoir pressure as a result of production. As the effective stresses on the reservoir rock increase, the probability of reservoir rock breakage and sand production increases dramatically (Araujo Guerrero et al., 2014). On the other hand, as some of the sand grains are separated or the cement between the grains is lost, the size of the pores in the near wellbore region also increases. This phenomenon can reduce the capillary force, which can weaken the forces between sand grains, and intensify the sand production.

Sand production consists of three steps: sand failure, sand erosion, and sand transportation (Kim et al., 2011; Salahi et al., 2021). After disturbing the equilibrium of stresses around the wellbore, the first step, sand failure, will occur. At this stage, the cementation between the sand grains has disappeared but the sand grains are still in place and do not move. Subsequently, the oil/gas flow rate provides the required drag force for sand erosion and detaches the sand particles and transports them through the porous media, wellbore, and pipelines (Kim, 2010). Therefore, in unconsolidated sandstone reservoirs, sand production is an inevitable drawback which must be controlled. The most common methods for sand production are restrictive production rate, mechanical methods include slotted liner, wire-wrapped screen, pre-packed screen, frac-pack, gravel pack, and high-rate water pack, chemical methods, and the combination of all these methods (King et al., 2003; Leone et al., 1990; Mathis, 2003; Xiang and Wang, 2003). Each method has its advantages and limitations and is selected according to the conditions and characteristics of the well and reservoir. Due to the lower production rate from the reservoir, the restrictive production rate method is not recommended. Also because of the operational problems and limitations, mechanical methods cannot be used in some wellbores. Therefore, using chemical methods to control and stabilize sand production in these wells will increase the efficiency of sand control operations and reduce operating costs associated with rigging and continuity of production from the well.

In this paper, chemical methods to control sand production, laboratory research and field operations in this scope will be discussed. The main challenges in chemical treatment are permeability and capillary force reduction in the near wellbore region. By injecting chemicals into the porous medium, the permeability of the area around the well decreases due to the reduction in the size of the pores. In addition, the decrease in the size of the pores after injection can increase the capillary force. But by injecting chemicals, it is also possible to change the wettability of the near wellbore region. If the wettability change is severe and causes a decrease in the capillary force between the grains, it can weaken the holding forces between the sand particles. Therefore, before chemical treatment, the effect of the desired substance on changes in wetting and permeability of the porous medium should be

investigated in the laboratory.

The paper structure is as follows. The second section presents used chemicals in sand production control method such as epoxy resin, porous resin, polymer gels and nanoparticles. In the third section, research and laboratory investigations to control sand production including methods such as thermal, nanoparticle, hydrogel, electrolysis, solder glass and resin injection are discussed. Also, the fourth section introduces the most important laboratory tests used in chemical control of sand production. Finally, field research and operations to control sand production by chemical injection and general steps of chemical fluid injection operation are discussed in fifth section.

2. Utilized chemicals for sand production control

As mentioned earlier, one of the most effective and efficient methods of controlling sand production is to inject chemicals to increase the rock strength, but having enough information about this will enhance the success of the chemical's injection process. The most important information needed in this subject includes all kinds of useable chemicals, preparation, and synthesis of intended chemicals, interaction between injected chemicals and reservoir fluids and physical/chemical resistance of injected chemicals in different conditions that some of them will be discussed in this section.

2.1. Epoxy resin

2.1.1. Characteristics of epoxy resin

The term epoxy resin refers to a group of reactive compounds having one or more epoxy rings. The number of epoxy groups in a molecule determines the performance of the resin. These groups are located at the end of the polymer chain and they can react with appropriate hardening reagents or react catalytically to form higher molecular weight polymers. After hardening, the epoxy polymers are tightly cross-linked and have high adhesion strength. Several important explanations regarding the structure of epoxy resin can be stated as follows: (1) Epoxy groups at both ends of the molecule and hydroxyl groups at the midpoint of the molecule are highly reactive, (2) the bulk of the epoxy resin backbone contains aromatic rings that provide high temperature and chemical resistance, (3) the aliphatic sequence between the ether bonds provides chemical resistance and flexibility, (4) resins can be low viscosity liquids or hard solids that low viscosity of resins can cause high penetration in porous media, (5) the high diversity of polymer structures is dependent on the polymerization reaction and the hardening agent, which results in variation in resin and high temperature hardening at low or high speeds and (6) the adhesion of epoxy resins is largely due to the secondary hydroxyl groups that lie along the molecular chain. Epoxy groups are generally used during hardening (Osumi, 1987).

2.1.2. Types of epoxy resins and their synthesis

2.1.2.1. Diglycidyl ether of bisphenol a (DGEBA). Epoxy resins were first introduced in 1964 by Ciba-Geigy. Diglycidyl ether of bisphenol A (commonly abbreviated BADGE or DGEBA) is an organic compound used as constituent of epoxy resins. The compound is a colorless solid (commercial samples can appear yellow) that melts slightly above room temperature. The most common commercial epoxy resin is known as DGEBA which is synthesized from the reaction of bisphenol A and epichlorohydrin in the presence of NaOH catalyst at 110 °C for 16 min (Fig. 1).

2.1.2.2. Epoxy novolac. Epoxy novolac resins are higher performance resins than DGEBA resins which are manufactured in several

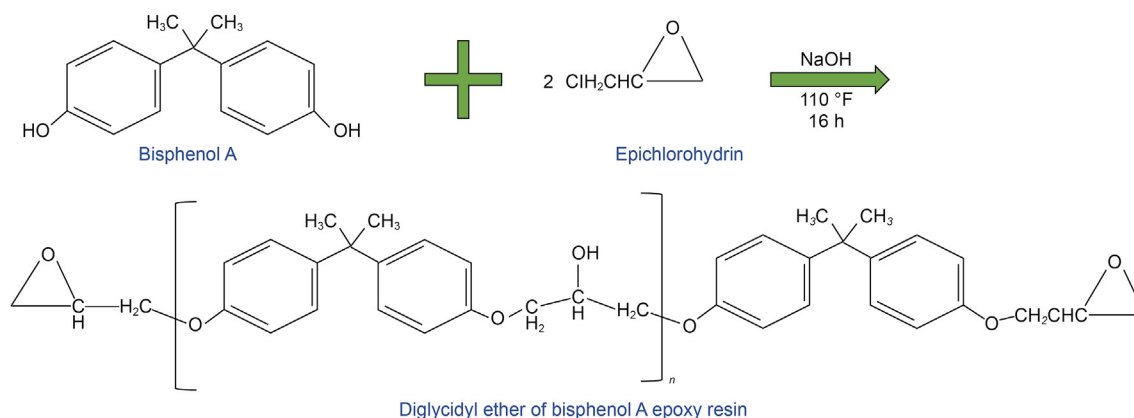


Fig. 1. The chemical equation of DGEBA epoxy resin (Pham and Marks, 2000; Schwartz and Goodman, 1982).

ways. The reaction of novolac phenolic resin with epichlorohydrin at base condition forms epoxy novolac resins. These highly viscous resins typically carry 2–6 epoxy groups per molecule. Highly cross-linked polymers with high temperature and chemical resistance by curing, but low mechanical flexibility is formed due to the high functionality of these resins. Fig. 2 shows the chemical reaction in which the epoxy novolac resin is formed (Kaji and Endo, 1999; Pham and Marks, 2000).

2.1.2.3. *Epoxy glycidyl ether tetraphenol ethane resin.* It is a solid resin (80 °C melting point) with a structure similar to that shown in Fig. 3 available commercially as EPON Resin 1031. Polyhydric phenols have been used for the preparation of diglycidyl ethers. From the reaction of polyphenol and 1: 2, 1: 2-(p-hydroxyphenol) ethane, an epoxy resin having four functional groups, tetraglycidyl ether tetraphenol ethane is prepared (Petrie, 2005).

2.1.2.4. *Diglycidyl ether of bisphenol F (DGEBF).* Diglycidyl ether of

bisphenol F (DGEBF) resins are designed to provide epoxy resins with greater flexibility and lower softening temperature than conventional DGEBA epoxy resins. DGEBF resins are formed from the formaldehyde reaction, phenol and epichlorohydrin. The structure of DGEBF resins is presented in Fig. 4 (Petrie, 2005).

2.1.2.5. *Aliphatic and cycloaliphatic epoxy resins.* Aliphatic and cycloaliphatic epoxy resins are produced from the epoxidation of olefin compounds. The epoxidation process involves the use of an olefinic or polyolefinic compound and a peracid (e.g., acetic acid) or other oxidizing substances such as hydrogen peroxide, molecular oxygen or even air. Several common epoxy cycloaliphatic resin structures are presented in Fig. 5 (Petrie, 2005).

2.1.2.6. *Aliphatic glycidyl ether polyols epoxy resin.* Polyols react with epichlorohydrin to produce polyol glycidyl ether epoxy resins. These resins are not used alone because of their water sensitivity and no overall resistance. However, they act as modifiers for DGEBA

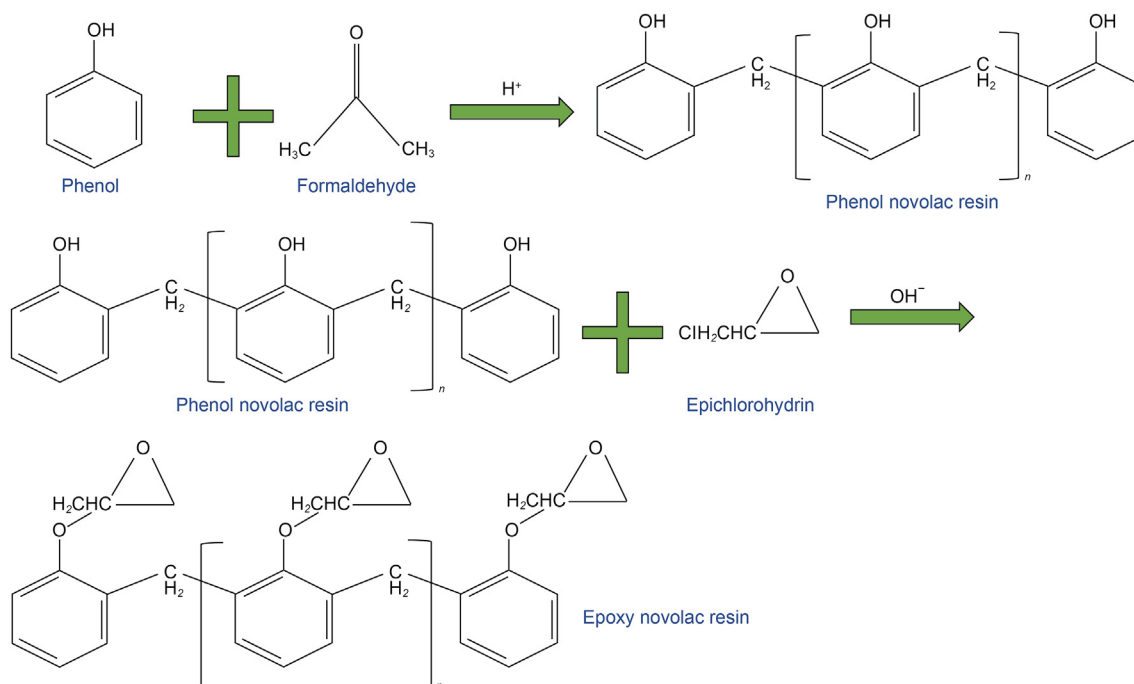


Fig. 2. Synthesis of epoxy novolac resin from phenol novolac resin and epichlorohydrin.

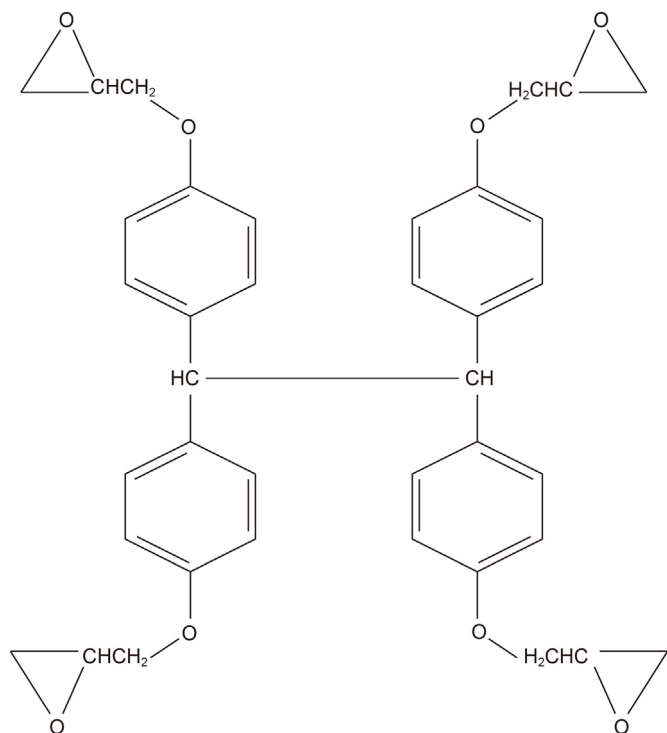


Fig. 3. Structure of epoxy glycidyl ether tetraphenol ethane resin.

epoxy resins. Special grades are made of epoxy glycidyl ether with compounds such as glycerol, polyglycols, pentaerythritol, and others. Other epoxy-polyglycidol resins are produced from the reaction of epichlorohydrin and polypropylene based on ethylene or propylene oxide. These resins are produced by reacting epichlorohydrin with poly in the presence of a catalyst, similar to phenolic-based glycidyl ethers. Fig. 6 shows the ideal structure of a flexible epoxy resin made of polyol (Bruins, 1968; Petrie, 2005).

2.1.2.7. Bromide epoxy resin. Conventional DGEBA epoxy resins are flammable during manufacture. In certain functions non-flammability is an important criterion. Flame retardant additives and chlorinated hardening reagents have been used to make non-flammable epoxy resins. Tetrabromobisphenol A is one of the non-flammable resins formed by the reaction of epichlorohydrin and bisphenol A. These resins gain their fire-retardant properties by substituting bromine on phenyl bisphenol A rings (Petrie, 2005).

2.1.3. Epoxy resin additives

Due to the widespread application of epoxy resins in different industries, one of the requirements of using such resins is to improve their properties by additives. For example, additives with an alkaline functionality can be used to accelerate the bonding time of resins (Hsu et al., 2012) and additives with anhydride functionality have excellent electrical properties and good chemical

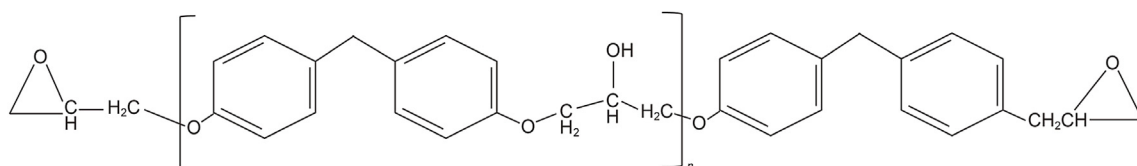


Fig. 4. Structure of diglycidyl ether of bisphenol F (DGEBF) resins.

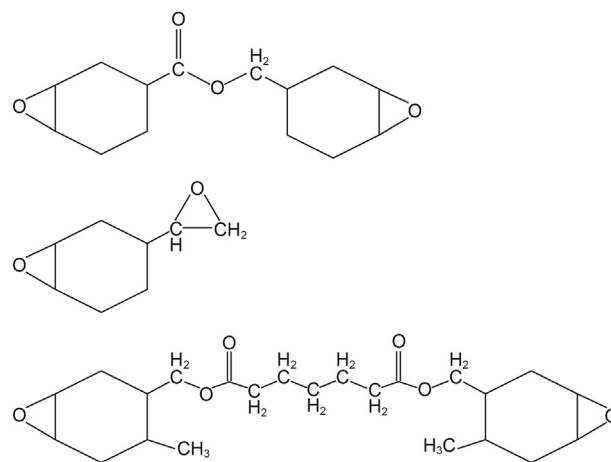


Fig. 5. Structure of several cases of cycloaliphatic epoxy resin (Petrie, 2005).

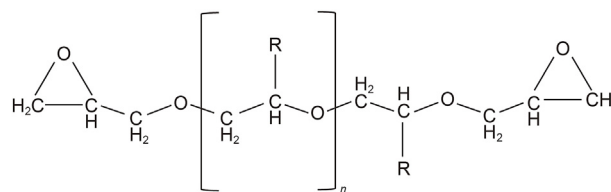


Fig. 6. The ideal structure of a flexible epoxy resin made of polyol.

resistance. Properties improved by these additives are generally accelerated by amines which are divided into three groups, including aliphatic, aromatic and cycloaliphatic amines (Foix et al., 2012; Frank et al., 2013). Additionally, organosilane compounds due to their silane groups can form Si–O–Si bond as the interface between resin and sand (Bezemer and Meijs, 1966; Hamby Jr and Strickland Jr, 1972). Adding sodium silicate to epoxy resin increases the compressive strength of sand. This increase in strength is governed by the amount of resin and sodium silicate, and if the resin is reduced, this reduced amount will be compensated by increasing the amount of sodium silicate (Anagnostopoulos and Hadjispyrou, 2004; Todd et al., 2001). Also nanoparticles play an important role in improving the properties of epoxy resins by increasing the surface to volume ratio, by modifying the nanoparticles with compounds having a suitable functional group such as silane, they are used as additives (Mishra and Ojha, 2016).

2.1.4. Resistance and stability of epoxy resins under different conditions

Since epoxy resins are exothermic, they have a softening point called glass transition temperature. Warming at temperatures above glass transition temperature makes the resin slightly soft and easily removed from the rock surface. Most epoxies decompose at 400 °C and become carbon ash. With the warming of an epoxy resin, hydroxyls generally react with epoxy or acid groups. Hence,

quadruple-functional diepoxy resins are formed that these resins are cross-linked with heat, they have greater chemical resistance after being hardened by heat than they are at room temperature (Petrie, 2005). After epoxy resin injection to the porous media, a high strength adhesion must be formed between the resin and the sand surfaces, but the presence of water in the formation can create a thin film of water which can prevent proper adhesion between the resin and sand. Therefore, surfactant reagents, a suitable solvent and cross-link reagent, can be used to eliminate disturbance of the formation water (Bezemer and Meijis, 1966; Bezemer et al., 1968; Davies et al., 1981; Hamby Jr and Strickland Jr, 1972; Nguyen, 2004; Parlar et al., 1998; Todd et al., 2001; Zhang et al., 2013).

The chemical resistance of epoxy resins to various chemical agents is very important in resin injection process. The choice of a suitable epoxy resin has an impact on the chemical resistance of the hardened resin. Also, the chemical resistance of the hardened epoxy resin to a solution is controlled by a variety of hardeners. For example, amine-hardened epoxy resin has good resistance to alkaline solutions and has good resistance to acidic solutions when the anhydride acid hardener reagent is used to harden the resin.

Also, the hardening reagent content is one of the factors that affect the resistance of epoxy resin to acid. The results show that the higher the hardness of the epoxy resin with the amine reagent, the faster the rate of adsorption of the sulfuric acid solution, however, there is no change in the sodium hydroxide or water

solution (Sembokuya et al., 2003). Table 1 presents a summary of the types of epoxy resins, their agents and the conditions in which they are used.

2.2. Porous resins

Porous resins are divided into two general categories: (1) micro-pore resins and (2) macro-pore resins. According to Stamberg and Valter classification, the difference between the two types of porous resins is in the pore-size. In this classification, if the pores in the resins are larger than 50 Å, they are called macro-pore resins. Otherwise, the porous resins are called micro-pore resins. In recent years, porous resins have been widely used in separation processes, especially in the water purification industries and carbon dioxide separation (Lu et al., 2013; Xu et al., 2003).

One of the primary methods to produce these resins is to react phenol and formaldehyde in the presence of water and a catalyst under special conditions. The result of this reaction is the formation of a water-insoluble polymer. The synthesized resin will have a color range from white to opaque that resin blurring will occur during gelation. The reaction product will not be porous if the water is removed from the polymer texture and the water and polymer are separated in two phases. Because, for the resin to be porous, water must be removed by heating from the resin texture after the process is complete and as the water comes out, the resin becomes porous (Mills and Alm, 1945; Robinson and Mills, 1949).

Table 1
Summary of the types of epoxy resins, their agents and the conditions in which they are used.

Epoxy resin	Agents		Compressive strength range, psi	Temperature, °F	Salinity, ppm	Hardening time	Literature
	Chemical	Role					
FURMEL-301	o-phosphoric acid Furmel	Hardener Catalyst	6000	176	10,000	400 min	Wasnik et al. (2005)
EPI-REZ SU2.5	N-methyl-2pyrrolidone 4,4'-diamino diphenyl sulfone N-(β-aminoethyl)-γ-aminopropyl-trimethoxysilane	Diluent Hardener Coupling	700	75	–	10–48 h	Dewprashad et al. (1997)
Phenol formaldehyde	Hydroxyethylcellulose HCl KH550 (with NH ₂ group)	Diverting Hardener Coupling	1100	140	20,000	24 h	Zhang et al. (2013)
Furan resin	Methanol, tert-butyl alcohol and acetic acid Acetic anhydride N(β-aminoethyl) γ-aminopropyltrimethoxysilane	Resin/water miscible organic solvent Co-solvent Coupling	>200	–	–	24 h	Shu (1996)
EPIKOTE 828	HCl, H ₂ SO ₄ and H ₃ PO ₄ Aromatic polyamines Isopropyl alcohol Dimethylaminomethyl substituted phenol SHELLVIS-50	Catalyst Hardener Resin forming solvent Catalyst Viscosifying	1700	80	150,000	16 h	Davies et al. (1981); Bezemer et al. (1968); Davies et al. (1981)
Epoxy silane A-186	Amine with a silane group	Resin to grain bonding	1100	–	50,000	–	Hamby Jr and Strickland Jr (1972)
Furfuryl alcohol (DUREZ33682)	C ₁₂ –C ₂₂ alkyl phosphonate N(β-aminoethyl) γ-aminopropyltrimethoxysilane Waterproof polymers containing hydroxyl group	Surface active Coupling Gelling	1200	200	150,000	48 h	Nguyen (2004)
Poly epoxy (EPON 828)	Multi-valence metal ions Galactomannan gum 2-ethyl-4-methylimidazole 4,4-diamino diphenyl sulfone Butyl lactate 3-glycidoxypropyl-trimethoxysilane Ethoxylated-nonylphenol-phosphat ester Sodium borate, sodium hydroxide	Cross-linking Gelling Hardener Diluent Coupling Surface active Cross-linking	>3000	–	–	–	Todd et al. (2001)

In the early 1940s, by sulfurizing porous phenolic resins, they were used for acid separation. Due to the high compressive strength of these resins, they were used to produce glucose and fructose. The mechanism of action of these resins is based on adsorption of a positive acid hydrogen ion. After the propagation of the use of porous resins, the base phenolic resins also showed good properties which made them suitable for use in the industry. Further investigation showed that these resins have high compressive and tensile strength, appropriate special surface and their texture in solid state is similar to that of sponge (Abrams, 1975). Base phenolic resins are used in air purifiers, cigarette smoke filters (Rainer and Bailey, 1981), and the food industry (Litzinger, 1974). Carboxylic resin can be described as the most porous polymer that has not been characterized for a long time. This resin has a cloudy color and is resistant to consecutive water absorption (swelling) (D'Alelio, 1944).

After the synthesizing of porous resins by ion exchange method and structural study of manufactured resins, many differences were observed and there was a need to define a new class of porous resins that these types of resins are called macro-pore resins. DVB commercial solutions are used as diluents in the production of these resins (Kunin, 1979). In fact, resins with a macro-pore structure are generally produced by the use of copolymer techniques. So that during the polymerization process of these resins, sedimentation occurs and the final product will be two-phase, includes the gel and the pore phase which comprises the spherical gel beads. There are a variety of methods for porous resins synthesizing that sedimentation and gelling must be occur simultaneously in most of them. There are some important tips that affect the overall resin properties such as correct selection of the bonding agent, the resin base phase (acidic of base) and property improvement processes for synthesizing porous resins (Bodamer, 1952).

During experiments to increase the porosity of phenolic resins, solvents such as isopropanol, methanol, mineral oil, naphthalene and toluene are not suitable. The porosity creation in the resins is actually due to their polymerization where monomers are polymerized in the presence of additives that do not play a role in the polymerization process and they usually act as solvents. Also, other additives can be used to eliminate this phase or to dry the polymer. Almost all studies have used a middle phase that is not soluble in the continuous phase to create porosity. This phase can be a solvent of cross-linker system or is incompatible with the formed polymer and is not able to dissolve it that some of these additives are listed in Table 2 (McBurney, 1952). Another method to create porosity in resins is a process known as pre-polymerization/co-polymerization. During this process, polymerization bonds are formed with time delay and porous space in the resin will be create (Abrams, 1975). It should be noted that the methods of making micro-pore in the resins include Friedel-Crafts alkylation, imidization, Sonogashira-Heihara surface coupling, homocoupling, Gilch coupling and cyclotrimerization (Dawson et al., 2012; Kuhn et al., 2008; Liu et al., 2015; Lu and Zhang, 2014; Ratta, 1999; Schonbein et al., 2017).

Table 2

Soluble and insoluble phases useable for several types of polymers for porosity creation (McBurney, 1952).

Polymer	Insoluble phase	Soluble phase
Styrene	Isobutanol	Toluene
Oxyethylene-coamoxypropylene	<i>n</i> -heptane	Ethyl benzene
Methyl methacrylate	Octoic acid	Diethyl benzene

2.3. Polymer gels

In recent years, polymer gel techniques have been broadly applied to control sand production in the oil and gas industry as the approaches allow sand production to be controlled while minimizing formation damage. Considering the operating conditions of wells and reservoirs, polymer gel methods offer a wide range of benefits including high injectivity, high thermal resistance, high mechanical resistance, high pressure resistance, high salinity resistance, and high penetration through pores (Lahalih and Ghloum, 2010).

A polymer gel system is divided into two categories: polymer solutions and aqueous solutions containing a cross-linking agent, termed gelant. In gelant mixtures, hydrophilic polymers are linked together by organic or inorganic cross-linking agents to form chemically and physically a three-dimensional network structure. Through the injection of a polymer solution into the well, a thin film is formed on the rock surface, thereby enabling the rock to withstand the overwhelming stresses associated with the high velocity of fluid near the wellbore. Therefore, this three-dimensional network with high thermal-mechanical resistance to temperature and salinity can control and manage sand erosion, followed by controlling sand production (Marandi et al., 2018). Generally, the types of polymer gel systems are classified into three main groups: *in-situ* cross-linked polymer gels, preformed polymer gels (PPG) and foamed polymer gels (Zhu et al., 2017).

Due to the chemical properties of each polymer gel systems and resins, the use of resins in oilfields leads to a reduction in formation permeability and at the same time it may increase operating costs (Marandi et al., 2018). In addition to this point, because resins are not environmentally friendly and also require multiple injections, it is technically and economically preferable to control sand production in oilfields using polymer gel systems (Lahalih and Ghloum, 2010).

3. Experimental investigations on sand production control

3.1. Thermal method

In 1964, Goodwin and Terwilliger (1964) conducted research on the consolidation of sand grains by crude oil oxidation. Combustion by hot air is a method of controlling the sand production from oil wells that in this method the crude oil oxidizes by injecting hot air into the reservoirs and continuing this oxidation will increase the viscosity of the oil, which will form coke or resin between sand grains. In oil reservoirs with light oil, heavy oil is injected into the reservoir to prevent and control sand production by oxidation heavy oil in near wellbore region. Results shows that consolidated sands by this method have a thermal resistance of more than 500 °F.

In addition, Osman et al. (2000) also carried out experimental studies of the sand production control by low temperature oxidation of crude oil. Unconsolidated sands with a mesh size of 20/30, saturated with crude oil with gravity 18–20 °API and brine at low temperature from 100 to 150 °C were subjected to air injection for 6–18 h, as the permeability reduction was in the range of 4.4%–5%. Also, it was found that higher oxidation temperature reduces the integration time and increases the compressive strength, but it has no effect on permeability reduction. Heavy oils require less oxidation time, and the permeability reduction is slightly higher than the heavier oils but has not significant effect on compressive strength. Generally, higher oxidation temperature decreases the integration time and increases the compressive strength of sand, but it does not have a significant effect on permeability reduction. As well as the amount of asphaltene in the crude oil diminishes the integration

time, increases the permeability reduction of the formation and it has no significant effect on the compressive strength of the integrated sands. In addition, the interstitial water saturation in the sample before oxidation has little effect on the integration time and the compressive strength of the sands, but the formation permeability is less than the dry state. It is necessary to mention that the presence of 4% clay in the formation reduces the integration time by about 25% which this is due to the adsorption properties and the large clay surface. The clay content results in higher compressive strength of consolidated sands.

3.2. Nanoparticles method

Nanotechnology is one of the main areas of science and engineering, where the majority of researchers have the ability to implement novel ideas to obviate those shortcomings leading to serious challenges in various industries such as oil and gas, food, pharmaceutical, and medicine (Akhter et al., 2022). In this area, much importance has been attached to the development of materials in nanoscale. Metal oxide nanoparticles, such as SiO₂, TiO₂, ZrO₂ and CeO₂, have gravitated much of recognition to enhance mechanical–thermal properties of the preferred system associated with control sand production in sandstone reservoirs (Gao et al., 2020; Ndolomingo et al., 2020). Silica nanoparticles are in widespread use owing to hydrophilicity property and high mechanical resistance of the selected structure under high salinity and temperature. In other words, silica nanoparticles contain a significant number of hydroxyl groups (OH) on the surface, which result in an increase in the mechanical stability of chemical methods under harsh conditions of reservoirs (Guo et al., 2022). In this section, the effect of silica nanoparticles on the properties of various systems including polymeric matrix, nanofluid, emulsion, and chemical composition used in oilfield has been investigated.

Baloochestanzadeh et al. (2021) investigated the effect of silica nanoparticles on the mechanical resistance of the polymeric network structure in the presence of sea water and formation water. They formulated nanocomposite preformed particle gel (NCPGG) loaded with silica nanoparticles to enhance mechanical properties under high salinity and temperature. In this study, the obtained results revealed NCPGGs loaded with 5 wt% SiO₂ enhanced the storage modulus (G') up to 800 Pa, when the sample was immersed in a sea water (SW)/formation water (FW) blend with salinity of 36,500 and 225,000 ppm, respectively, at 80 °C. Furthermore, Fig. 7 illustrates the effect of salinity on the structure with and without silica nanoparticles content. As shown in the figure, the salt ions result in a phenomenon known as screening effect, which has negative effects on the structure both chemically and mechanically. In this regard, silica nanoparticles can mitigate this issue with forming hydrogen bonds, which make the structure more dense and rigid in contact with the saline solution (Baloochestanzadeh et al., 2021; Zhu et al., 2017). Moreover, the taken SEM images from the two samples confirm the positive effect of silica nanoparticles in the presence of NaCl saline solution with a concentration of 50,000 ppm. As observed in Fig. 8a, the sample loaded with silica nanoparticle can be recognized due to the fact that SiO₂ forms physical interconnections into the network, which keep the structure secure in the presence of salt ions, whereas the sample with no SiO₂ collapsed in this situation (Fig. 8b) (Baloochestanzadeh et al., 2021).

Bahri and Khamehchi (2021) aimed to study the effect of nanofluid on sand production. In this experimental research, silica nanoparticles were used to formulate a smart nanofluid containing smart water and nanoparticles with a concentration of 2000 ppm. Fig. 9 shows the FESEM images from the rock soaked in the nanofluid. As shown in the figure, it can be concluded that silica

nanoparticles cover the rock leading to preventing the migration of mineral separated from the surface. In fact, silica nanoparticles are in the form of charged particles, which have hydrophilic chains (OH), and can convert the oil–wet property of the rock to water–wet. Therefore, this alternation increases oil production coupled with a decrease in sand production as a result of less the surface contact with the smart water and leaching the rock (Bahri and Khamehchi, 2021).

Kalgaonkar and Chang (2017) conducted research on the consolidation of sand grains using colloidal nanoparticles. In this investigation, positive-charged colloidal nanoparticles, consisting of cationic modifiers and ionic strength modifiers, were used for sand consolidation which is placed as a single pill at bottom-hole. As this pill forms a thin layer of tough gel around the sands at reservoir temperature, it cements the particles together, and does not significantly reduce the formation porosity and permeability to ensure easy flow of produced hydrocarbons or injected water. These cationic nanoparticles are initially in low viscosity emulsion form, then with the addition of an activator it becomes a hard composition, where the positive-charged nanoparticles are placed around the sands due to their negative charge as a result of the electrostatic forces. Furthermore, the repulsive force among the positive charges will maintain the composition viscosity low and prevent premature hardening of the composition to allow sufficient time to reach the bottom-hole, and this repulsion also prevents the nanoparticles from agglomeration (Kalgaonkar et al., 2017).

Also Mishra and Ojha (2016) was mainly focused on sands consolidation using nanoparticles to deal with this challenge in weak sandstone formations. This study was aimed to formulate a novel chemical composition loaded with nanoSiO₂ and UF (urea formaldehyde) resin for sand consolidation applications. Results show that using nanoSiO₂ and UF resin can consolidate loosely sands so that they have compressive strength greater than 2000 psi with a little reduction in the formation permeability.

3.3. Hydrogels method

Hydrogels are formed by mixing the polymer solution with a suitable cross-linker solution via a polymerization process at a specific temperature (Salehi et al., 2014; Xianjie et al., 2007) which are preferable to other chemical methods for sand control process owing to its adjustable viscosity, lower required concentration and good injectivity (Bai et al., 2015; Karimi et al., 2014). In this regard, Salehi et al. (2019) investigated a chemical method based on taking advantage of hydrogels to control sand production in poorly consolidated sandstone reservoirs. In this study, polyacrylamide/chromium triacetate hydrogel has been proposed as a chemical method to assay sand production in a synthetic sand pack system. The compressive strength of the sand pack is measured before and after the injection of the synthesized hydrogel into the sand pack system. Results show that the compressive strength of the sand pack was increased about 30 times by injecting 0.5 PV of the hydrogel. It is worth mentioning that high salinity of formation connate water plays a vital role in the stability of injected chemical agents for sand consolidation. So, in this experimental investigation, hydrogel stability in the presence of salt, in particular divalent cations, has been studied. The maximum strain value applied on hydrogel in the presence of CaCl₂ was only about 201% compared to 1010% in the presence of distilled water. The experimentally determined thermal resistance of the synthesized hydrogel also is approximately 300 °C. Finally, they concluded that increasing the concentration of the polymer and the cross-linker enhances the strength of hydrogel. Fig. 10 depicts SEM images of the two hydrogel samples with a polymer concentration of 9500 and 7500 ppm and a 0.5 weight ratio of cross-linker/polymer,

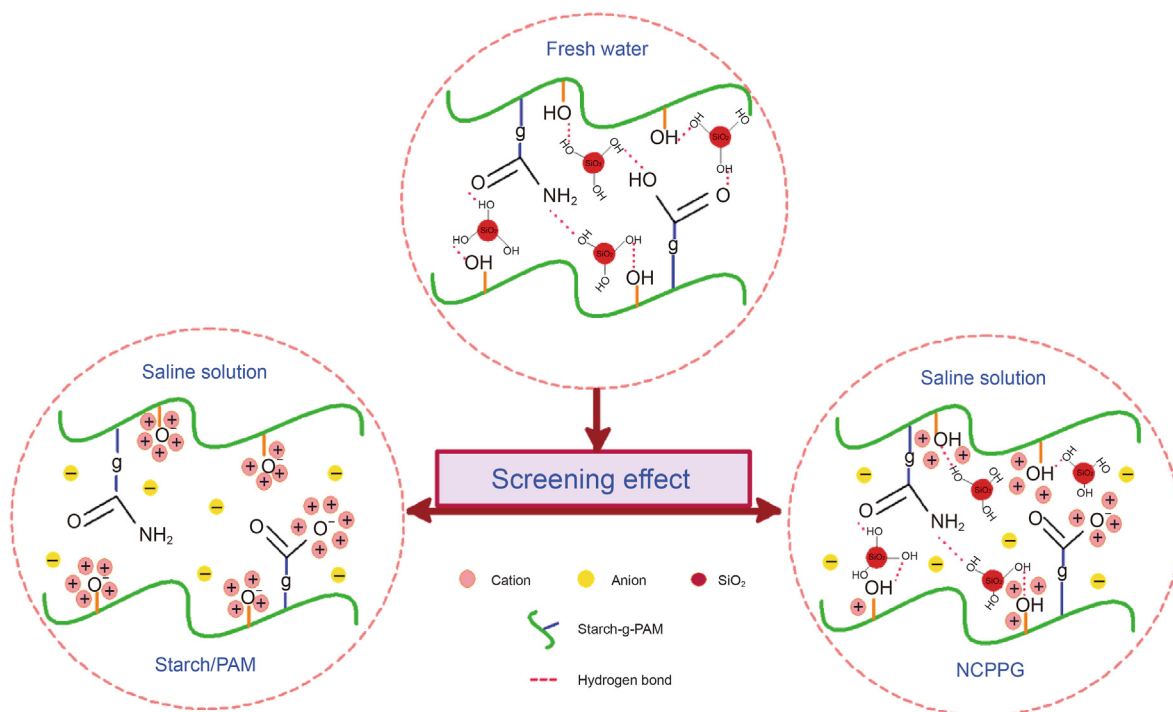


Fig. 7. Schematic of screening effect on the network structure in the presence and absence of silica nanoparticles (reproduced from Baloochestanzadeh et al., 2021).

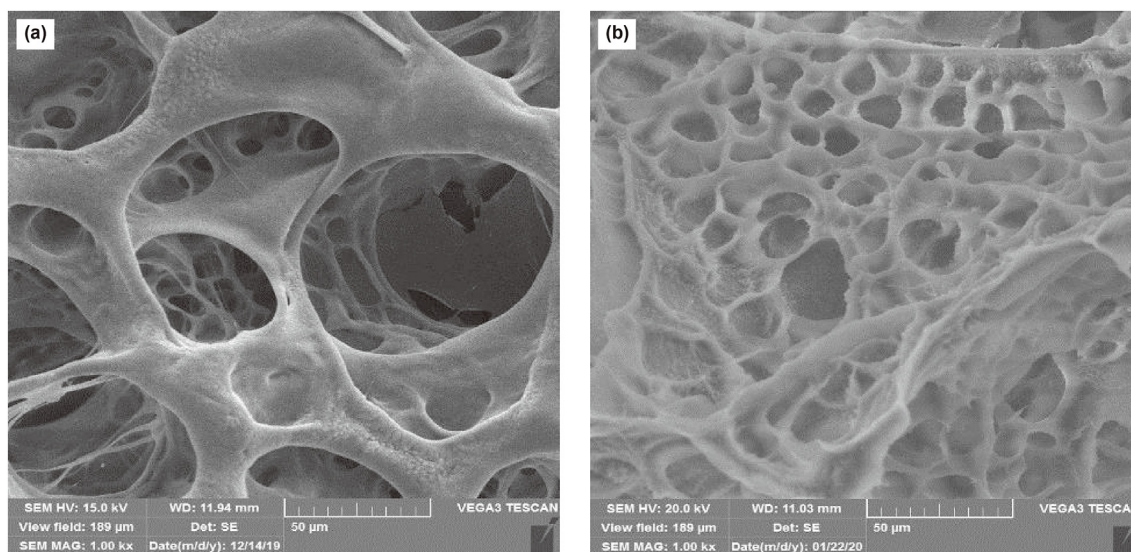


Fig. 8. The effect of saline solution on the skeleton of samples (a) with silica nanoparticles, and (b) without silica nanoparticles (reproduced from Baloochestanzadeh et al., 2021).

respectively (Salehi et al., 2019).

Another research concentrating application of hydrogels in oilfield is contributed to double network structure hydrogel with good injectability. Kang et al. (2022) prepared poly (2-acrylamide-2-methylpropanesulfonic acid–copolymer–acrylamide) microgel and polyacrylamide as a hydrogel via a free radical polymerization process to evaluate viscosity as a function of P(AMPS–co–AM) particle content. The obtained results reveal that when the dosage of the hydrogel is 0.5%, the viscosity of the pre-polymer solution is measured 28 mPa s, whereas the dosage of the hydrogel is 1.5%, the viscosity of the mixture increases significantly to 980 mPa s. In this study, that synthesized hydrogel with low viscosity could be a suitable candidate

leading to a successful injection into the target zone of formation (Kang et al., 2022).

3.4. Electrolysis method

In this method, a catalyst is injected into the near wellbore region to active the sands and after that, the metal layer deposits spontaneously on the sand grains by injecting several aqueous solutions of metal salts including a chemical reducing agent. To this end, Torrest (1975) was conducted laboratory studies in electrolysis nickel sand consolidation. Consolidation of loosely sands by electrolysis of nickel catalyst from aqueous solution provides an

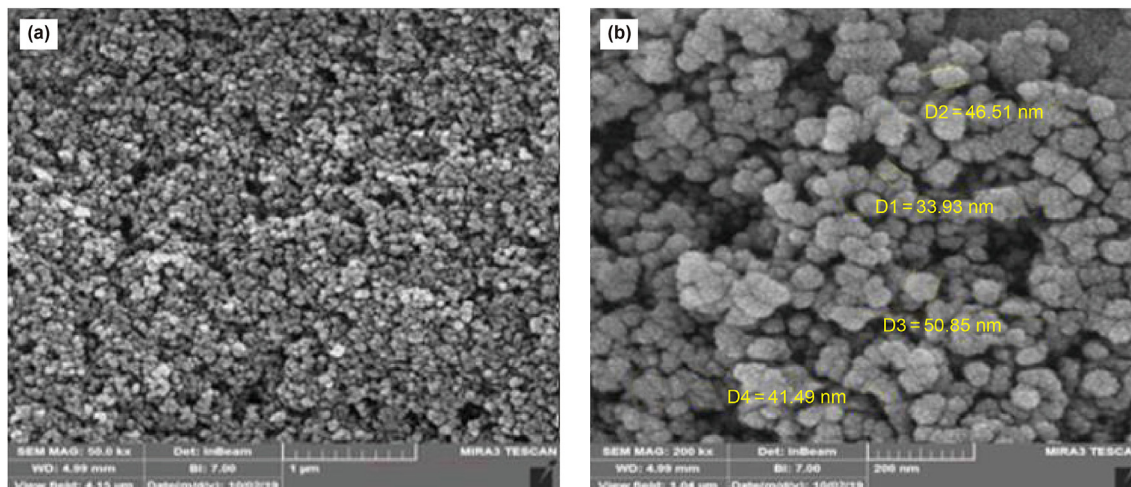


Fig. 9. The surface of rock immersed in the smart nanofluid. (a) The absorbed silica nanoparticles on the surface and (b) the size of silica nanoparticles absorbed on the rock (reproduced from Bahri and Khamehchi, 2021).

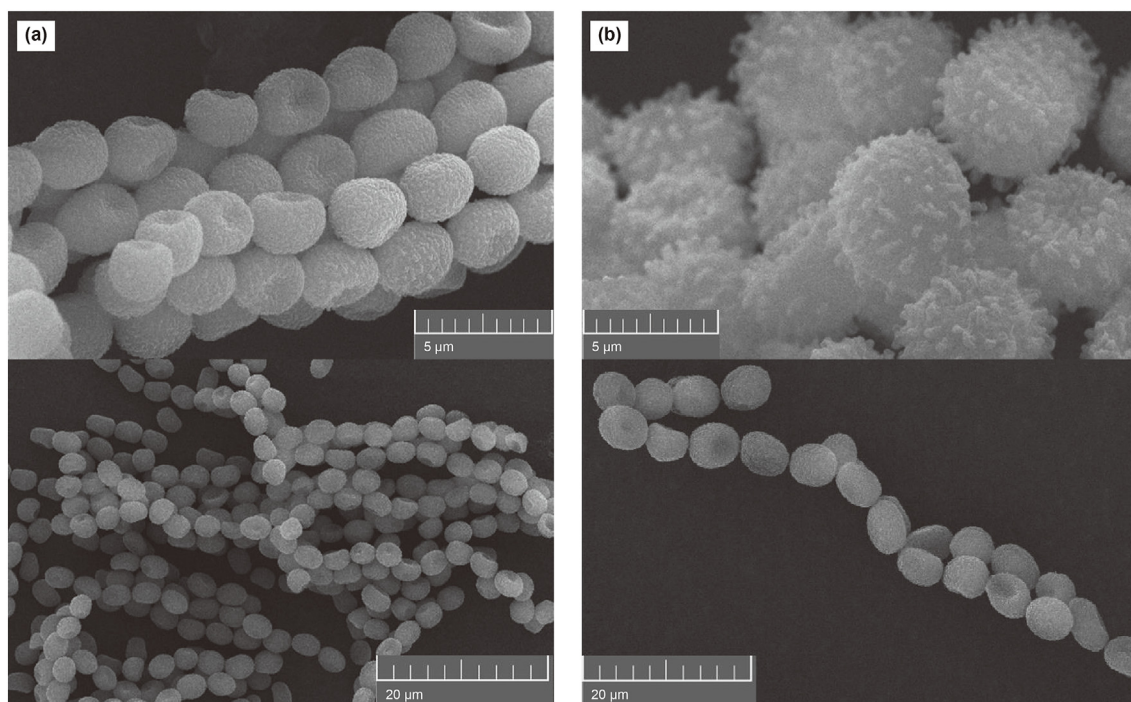


Fig. 10. SEM images of hydrogel of polymer concentration of (a) 9500 ppm and (b) 7500 ppm (0.5 cross-linker/polymer weight ratio) (reproduced from Salehi et al., 2019).

alternative to resin or plastic in special cases. It has been developed for applications at higher temperatures up to about 550 °F, which are available for the full range of reservoir temperatures and nickel-consolidated sands have a much higher compressive strength than organic cement.

3.5. Solder glass method

In 1981, Aslesen et al. (1981) conducted laboratory experiments on consolidation of sand grains by solder glass. This method is an *in-situ* consolidation technique and has good resistance to temperature and is well resistant to high-speed fluids that is why there is no limit to the production rate of the reservoir. In addition, the formation damage (porosity and permeability reduction) by this

method is very low. In this process, forward combustion is used. A glass made of lead oxide, zinc oxide and silica melts at 735 °F and devitrifies to a coherent crystalline structure after is heated to at least 825 °F for 1 h. This causes high internal strength, can withstand up to 1200 °F, is resistant to many chemical reactions and it can be dissolved in water solution, sodium hydroxide and sodium silicate. If this solution is injected into the near wellbore region and heated to the appropriate temperature, the formed crystals can strengthen the sand grains together. However, during this process, the permeability and porosity must be kept constant, and the material must be homogenized. Homogeneous deposition of this material between sand grains requires pores to be clean and dry that this is done by injecting hot air and combustion, then injection of the solution and continuous injection of air without heat will

moisten the solution and sand grains. Continuing to inject air will disperse the glass material into the cleansed sands/pores and expel the water from those, eventually causing a homogeneous deposition of this material on the sand grains. The disadvantages of this method include time consuming and high cost.

3.6. Resin injection

Spain (1967) introduced a method based on the use of a type of water-soluble aldehyde-catalyzed resin and a type of hydroxy-aryl. This invention is a way to fortify loosely consolidated sands that create many problems for oil production of sandstone reservoirs. The resin is synthesized from the reaction between a water-soluble aldehyde and a low molecular weight hydroxy-aryl reacting with an alkaline or acidic catalyst. When these compounds are injected into an unconsolidated formation below the surface, a resin is formed which cements the sand grains together. Although water-soluble aldehydes are used, formaldehyde, acetic acid, propionaldehyde or mixtures of them may be preferred. Resin efficiency is lowest where sands are most compact and is highest where sands are compacted with increasing resin solution.

Studies accomplished by Dewprashad et al. (1997) discuss in sand production control using epoxy resin in high temperature. In this study, a high temperature epoxy resin (HT) system is introduced that effectively integrated the loosely consolidated sands. This new system has several advantages over previous epoxy systems encompassing more safety, greater compatibility with acidic liquids and higher compressive strength. In addition, epoxy resin and hardening resin can be prepared and stored for a long time and used if necessary. This resin system has less impact on the gel breakers and does not change the pH of the fluid.

Kotlar et al. (2005) investigated in sand consolidation by injecting three stabilizing chemicals (organosilanes, polymer and urea/urease) into the sandstone formation. The chemicals used in this investigation were aimed at residual resistance increment and they are not intended to prevent shear stress in the matrix. Ideally, chemicals can add some elasticity to the matrix. Elasticity increment means that the matrix is better able to tolerate abrupt changes in stress conditions. In addition, injected chemicals should not reduce the permeability of the formation too much and should be environmentally friendly. They concluded that all three chemicals reduce sand production. But the best overall chemicals with respect to a combined effect of good sand consolidation and moderate permeability reduction seem to be the organosilanes.

In 2009, Yang and Totti conducted research to consolidate sand grains by injecting a mixture of hydrocarbon-resins into the weak sandstone formations. In this method, a compressed hydrocarbon solution, a resin or a resin-forming mixture is injected and dispersed into the porous media and the loose sand grains become strength permeable formation. The hydrocarbon-resin mixture has a surfactant in which the resin is selected from the group consisting of furan resins, urea-formaldehyde resins, phenol formaldehyde resins, epoxy resins and polyurethane resins. Also, Pavlich and Calvert (1967) introduced a new method of controlling sand production by injecting some kind of resin into oil wells. The resin used in this method is a phenol-formaldehyde condensation product that is soluble in aliphatic alcohol (methanol to butanol). This technique involves pre-incineration of the well with hydrocarbon liquid prior to injection of the resin and also the well is washed by a hydrocarbon liquid after resin injection operation.

Kalgaonkar et al. (2017) accomplished their research on sand stabilization by resin with a type of permeability enhancer. The newly developed chemical system is based on the resin with the chemical being hardened at reservoir temperature which has advantages including easy mixing and restoring permeability. Also,

other authors carried out similar experimental research of sand consolidation by resin injection to prevent or mitigate sand production problem (Dehghani et al., 2013; Madasu and Vo, 2016; Marfo et al., 2015; Talaghat et al., 2009).

Finally, according to the cases discussed in this article, the challenges of chemical methods can be enumerated. In the case of resin injection, one of the most important challenges ahead will be the chemical resistance of the resin against various chemicals. The choice of a suitable resin has an impact on the chemical resistance of the hardened resin, which can be evaluated in the laboratory, before any injection process. Also, limitations on the use of resins include reducing the permeability of the area around the well, as well as the reaction of the injected resin with the materials produced from the reservoir. In order to overcome the limitations of resins, future studies can be conducted on the synthesis of porous resins, to reduce the permeability-reduction of the area around the well, in addition to extensive studies of resin additives to reduce the reactivity of the resin with the products produced from the reservoir. Regarding polymer gels, it seems that we should take into account the below limitation and also present a solution in order to overcome this challenge. Owing to the fact that gel syneresis is one of the biggest problems in gel treatment of hydrocarbon reservoirs with the aim of control sand production, the effects of various contributing factors on behavior of gel syneresis under harsh conditions must be considered comprehensively. In this context, formulating and optimizing the structure of polymer gel with suitable monomers, nanoparticles, and cross-linker agent would be one of the practical keys to solve this issue and enhance the stability of the system in the presence of saline solutions, if not the most practical one. Therefore, the mentioned key would have a great potential to pave the way for more success in controlling sand production of oilfields. One of the chemical treatments for sand production is nanoparticle utilization. The main challenge in this operation is choosing the suitable nanoparticle for injecting into the near well bore area. For this purpose, wide laboratory investigation is needed. Because the nanoparticle performance in reservoir condition is the key factor for this technique. Also, the main limitation of nanoparticles is their cost for an industry operation. Although some study for nanoparticle method was performed, but investigation of various nanoparticle, such as nanocomposite, is required in sand production control. In the thermal method, possibility of success of this method, depending on the type of reservoir oil, is the challenge for chose a candidate well for this operation. Hence, this method can reduce the permeability of the near well-bore region, so, future works for mitigation of permeability reduction is inevitable. In one of the few studies on the method of electrolysis, the nickel solution is introduced for sand consolidation by the electrolysis mechanism, but the most important challenge in this scope is the possibility of using this material for all sandstone reservoirs. Therefore, it is needed more investigations for other materials that can be used in the electrolysis method. Although not many studies have been done in this field so far, but it seems that the most important limitation of this method is the possibility of electrolysis in reservoir conditions. In the solder glass method, the main challenge is the providing the required temperature for operation fulfillment. Also, high cost and time consuming are the limitation of this method. Because of that, a future work for decreasing the cost operation is needed for this method. Eventually, the summary of the challenges, limitation, advantages and required future work is presented in Table 3.

4. Laboratory evaluations in sand consolidation study

In this section, the most important and most commonly used tests for experimental investigations of consolidating loosely sands

Table 3
Comparison of chemical treatments for sand production.

Methods	Challenge(s)	Advantage(s)	Limitation(s)	Future work(s)
Resin injection (Bezemer and Meijs, 1966; Davies et al., 1981; Dewprashad et al., 1997; Hamby Jr and Strickland Jr, 1972; Lu et al., 2013; Mills and Alm, 1945; Nguyen, 2004; Shu, 1996; Stamberg; Valter, 1970; Todd et al., 2001; Wasnik et al., 2005; Zhang et al., 2013)	Chemical resistance of resin	Easy method Low cost	Permeability reduction Chemical reaction of resin	Synthesis of porous resins to permeability-reduction mitigation Resin additives to reduce the reactivity of the resin
Polymer gel (Lahalih and Ghouloum, 2010; Marandi et al., 2018; Zhu et al., 2017)	Gel syneresis	Formation damage minimization High penetration through pores	High costs Complexity of use	Formulating and optimizing the structure of polymer gel with suitable monomers, nanoparticles, and cross-linker agent
Nanoparticle (Bahri and Khamehchi, 2021; Baloochestanzadeh et al., 2021; Guo et al., 2022; Kalgaonkar and Chang, 2017)	Choosing the suitable nanoparticle	Effectiveness in sand consolidation	High costs	Wide study for various nanoparticles
Thermal (Goodwin and Terwilliger, 1964; Osman et al., 2000)	Possibility of success of this method, depending on the type of reservoir oil	No need for complex chemicals	Permeability reduction	Mitigation of permeability reduction
Electrolysis (Torrest, 1975)	Possibility of using current introduced material for all sandstone reservoirs	Formation damage minimization	Possibility of electrolysis in reservoir conditions	Wide study for various materials that can be used in electrolysis method
Solder glass (Aslesen et al., 1981)	Providing the required temperature for operation fulfillment	Constant porosity and permeability during the process	High costs Time consuming	Required studies for decreasing the cost operation

are presented.

4.1. Brazilian test

In this experiment, a specimen of rock is loaded by two opposing normal strips at the margin of the disk periphery and a load, *P*, is applied into this specimen which has a radius and thickness of *R* and *L*, respectively (Fig. 11). The loading rate may vary from 10 to 50 kN/min depending on the specimen material. In the standard method of ISRM, the tensile strength of rocks, σ_t , is calculated from the equation:

$$\sigma_t = \frac{P}{\pi RL} \tag{1}$$

Eq. (1) engages the elasticity theory for isotropic continuous media and indicates the stress of the perpendicular tensile stress loaded at the center of the disk at failure. If the specimen is anisotropic and has weak plates, the specimen should be prepared

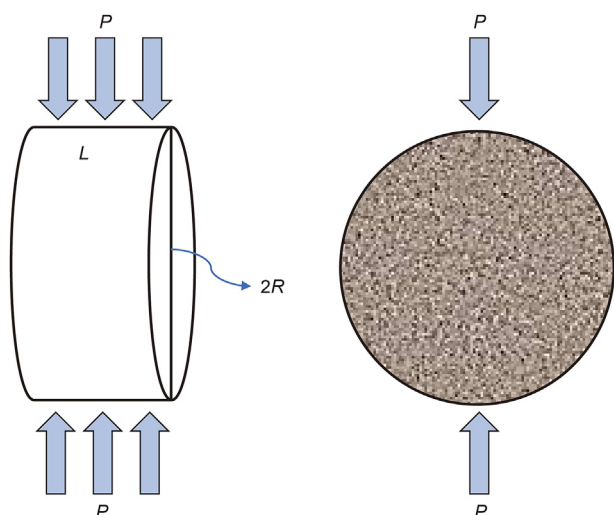


Fig. 11. Brazilian test method for a disk shape specimen.

so that both the directions can be tested in parallel and perpendicular to such plates. Fig. 11 shows a Brazilian test method for a disk shape specimen (Claesson and Bohloli, 2002).

4.2. Compression test

Compression test shows how the material will react when it is being compressed. Compression test can specify the materials behavior and response under crushing loads and to measure the plastic flow behavior and ductile fracture limits of a material. The test specimen is placed in between two plates that distribute the applied load across the entire surface area of two opposite faces of the test specimen and then the plates are pushed together by a universal test machine causing the specimen to flatten. A compressed specimen is usually shortened in the direction of the applied forces and expands in the direction perpendicular to the force (Chua et al., 2017). Fig. 12 presents a typical compression test apparatus and a general schematic of compression test procedure is portrayed in Fig. 13.

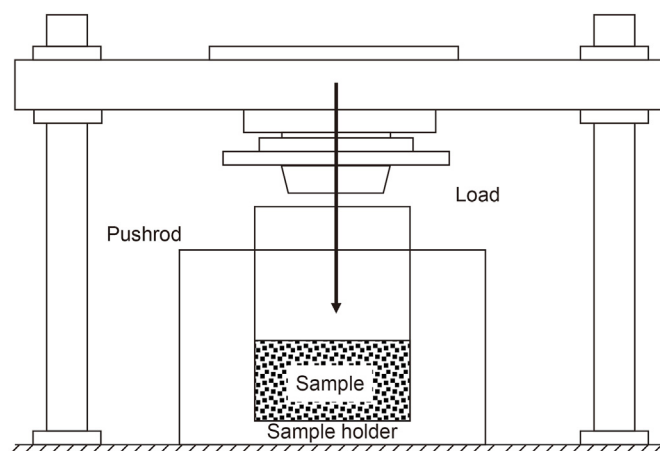


Fig. 12. A compression test apparatus and test specimen.

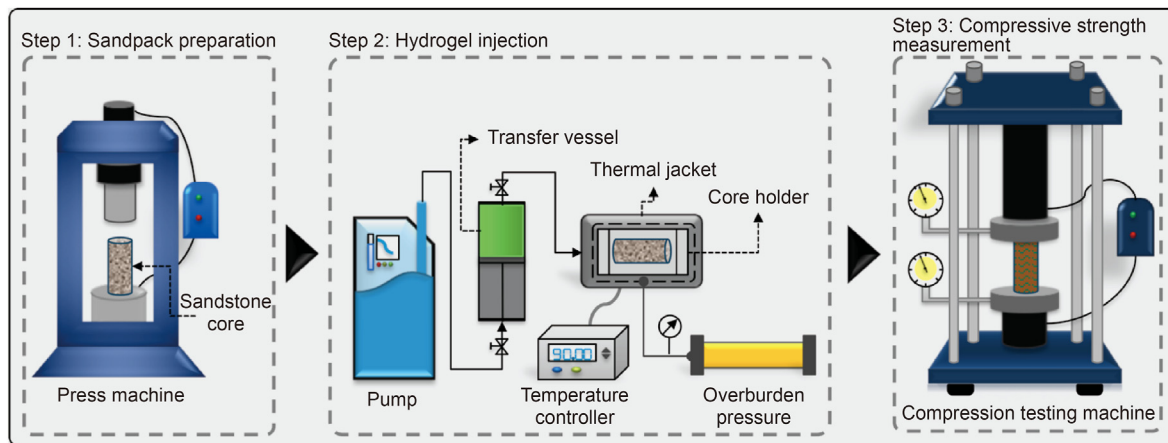


Fig. 13. Schematic of the compression test procedure (reproduced from Salehi et al., 2019).

4.3. Triaxial test

Conventional triaxial testing is a common experimental method that is usually used to obtain shear strength parameters for different types of soil in depleted or unburned conditions. This laboratory test involves placing a cylindrical soil specimen against radial pressures (confined pressure) and controlled increases in axial pressures or axial displacements. The specimen is sealed vertically with a thin rubber membrane, and placed between two plates in a pressure chamber. The top plate can move vertically and apply vertical stresses to the specimen. Hence, the axial pressure/stress of the specimen is controlled by the movement of this vertical axis. The enclosure pressure is also controlled by the water pressure around the specimen in the pressure chamber. By measuring the exact volume of moving water, the specimen volume change is also controlled (ASTM International, 2007, 2011). Fig. 14 illustrates the schematic of triaxial test apparatus.

4.4. Hollow cylinder test

The apparatus of the hollow cylinder test has a main pressure vessel for a hollow cylinder specimen of a weak reservoir. The pressure vessel that is shown in Fig. 15 includes the cell for applying

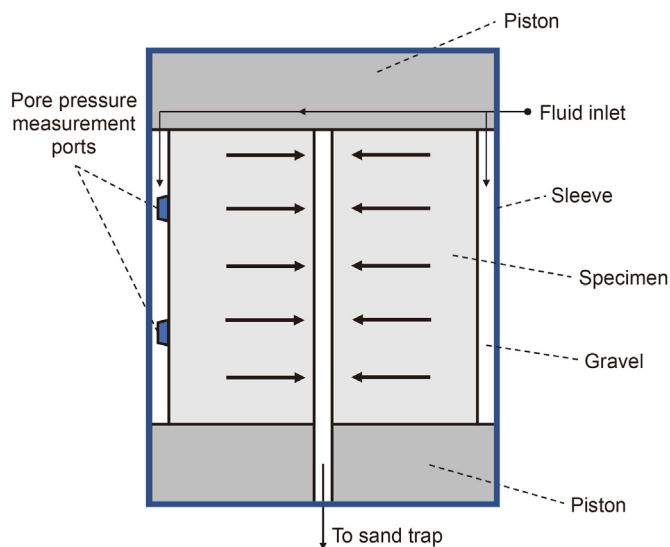


Fig. 15. Schematic of hollow cylinder test setup (reproduced from Papamichos et al., 2001).

confining pressure, the top and bottom loading pistons and the base plate for exerting the axial load and a sand trap for monitoring the produced sands. The loading system comprises also equipment for injecting fluid through the upper specimen surface. The experiment is accomplished by monotonous or step-wise increment of the external stress and flow rate. By using this setup, erosion and production of loosely sands under different condition (various external stress and flow rates) can be investigated (Kotlar et al., 2005; Papamichos et al., 2001; Tronvoll et al., 1997).

In this section, most commonly laboratory test which are fulfilled in sand consolidation by chemicals have been introduced. Although, there are more laboratory tests that can be used in chemical sand consolidation investigation. Table 4 summarizes some of these laboratory tests.

5. Field research and operations

Successful chemical injection operation to control sand production is an effective and efficient remedy to deal with this problem and will be economically beneficial. In this section, some field operations were presented and discussed.

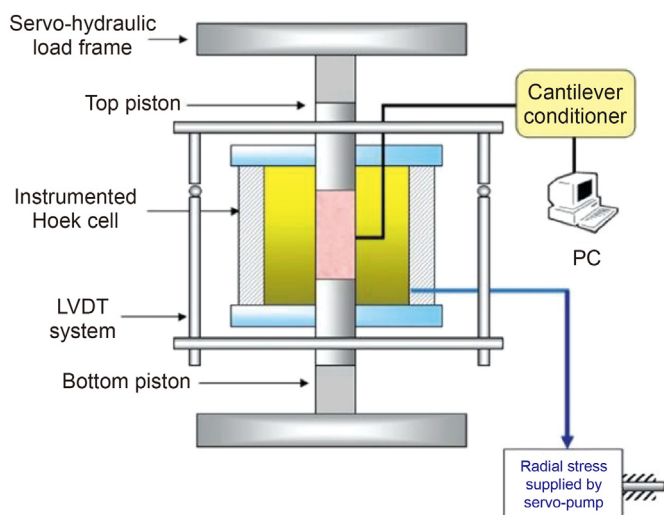


Fig. 14. Triaxial test apparatus schematic (reproduced from McPhee et al., 2015).

Table 4
Laboratory tests used in chemical sand consolidation.

Laboratory test	Evaluated qualitative and quantitative parameters	Literature
Brazilian test	Tensile strength of the rock	Li and Wong (2013); Andreev (1991)
Sieve analysis	Determination of particle size distribution	ASTM International (2019)
Direct shear test	Performance evaluation of the system used to improve sand production Determine the shear strength parameters for a sand using the direct shear test	Kisan et al. (1986)
Sanding test	Max. confining stress (psi) Max. flow rate (cm ³ /s) Nominal sanding rate (LB/1000 bbls)	Chin and Ramos (2002)
Cavity failure test with and without fluid flow	Consolidation stress (MPa) Mean grain size (μm) Stress at non-liner cavity closure (MPa) Stress at AE-rate increase (MPa) Formation damage Plastic consolidation	Tronvoll et al. (1997)
Hollow cylinder test	Max. confining stress (MPa) Max. flow rate (L/min) Mean grain size (μm)	Papamichos et al. (2001); Kotlar et al. (2005)
Sand production model set-up	Determining the amount of sand produced under different confining pressures and flow rates Effect of different oil viscosities Conducting sand granulometric analysis before and after experiment	Adeyanju and Oyekunle (2011)
Bottle test	Evaluate the gelation time Evaluate gel strength Evaluate heat resistance Determine syneresis time	Salehi et al. (2019)
Compression test	Determine the hydrogel composition of hydrogel and polymer (resin) Compressive strength measurement Compressive strength and reduction in permeability after the consolidation treatment	Salehi et al. (2019); Mishra and Ojha (2016)
Evaluation of gelation time	Measure gelation time Effect of composition and temperature on gelation time	Kalgaonkar et al. (2017)
Batch screening tests	Check the effectiveness of resin or nanoparticles in consolidating the loose sand	Kalgaonkar and Chang (2017)
Core flooding (reservoir conditions)	Max. flow rate measurement	Villesca et al. (2010)
Back flow test	Interaction between water base resin, rock and water	Villesca et al. (2010)
X-ray CT scanning and scanning electron microscope (SEM)	Investigation of the penetration of the consolidating fluid Examination of the formation in the pores of the formation	Villesca et al. (2010); Salehi et al. (2019); Kalgaonkar et al. (2017)
Triaxial test	The shear strength parameters, namely friction angle, cohesion, angle of deviation	ASTM International (2007, 2011)

According to Fitzgerald et al. (1966), hot air injections have been used to fortify sand production in one of the wells in California, U.S. Hot air injection into the well continues until oxidation occurs and coke is formed that causes sand strength increment. After performing the operation, they concluded that (1) this method can strengthen the loosely sands in wells that produce high viscosity oils up to a maximum production rate of 150 bbl/day, (2) the amount of hot injectable air should be limited and not cause a fire in the well, (3) the heat generated by air injection can stimulate the well, (4) this method will be successful in reservoirs containing high viscosity oil with an oil saturation over 40% and water saturation below 60%, and (5) if immediately after the operation oil is produced from the well, it may produce a little bit of sand, but after a time this will stop.

The low temperature oxidation method was also implemented for sand consolidation in one of the Saudi Arabia fields. In this method, by injecting high-content heavy hydrocarbon fluids, a thin layer of hydrocarbon fluids is imposed on the surface of sand grains and by injecting oxygen-containing gas at low temperature, oxidation is occurred and sands strength increase by forming coke between them. In one of the wells in mentioned field which had severe sand production problems and also had a high rate of water production, this method was tested and found to be a reliable method for controlling sand production and it is also safe and economically is expedient. After applying this method, the oil production rate increased 10 times and no sand production was observed during the 3 months (Aggour et al., 2007).

Phenolic resin has been used in several fields in southern Louisiana, USA for sand production prevention. In this case, phenolic resin (plastic phenol formaldehyde) was used in 545 wells in several oil fields in this region, 75% of which were successful and those that did not succeed, succeeded in the next steps. Advantages of this method include compatibility with all well completion tools and techniques and high flexibility in all wells, whether normal or tubing-less wells. The oil production reduction in this method is very mild and only occurs in wells that have very low deliverability (Rike, 1966).

Epoxy resin has used in many cases before, but none have ever been able to achieve acceptable low viscosity. In addition, the activator agent has always been added prior to pumping the resin, which has caused problems such as solidifying the resin before reaching the desired layer and having a viscosity of about 80 cP may cause fractures and ducts in the weak layers. Field studies by Shaughnessy et al. (1978) show that formation fracturing will not occur if the viscosity is 30 cP or preferably 20 cP. Application of a low viscosity epoxy resin was performed in 14 wells and sand production stopped in 11 wells. In those 3 wells, there were considerable evidences that very poor primary cementation caused this situation.

The use of polymerized organic materials and their catalysts in gas fields in France and in oil fields in Romania and the U.S. has been carried out to control sand production. In this process, injections consist of (1) polymerized organic matter and its catalysts and (2) oxygen flow. The bonding between sand particles results

from the chemical reaction of organic materials and oxygen and also because of the gas flow, formation permeability is maintained. The results of field tests show that this method is applicable for reservoirs with a pressure and temperature below 1450 psia and 80 °C, respectively and a clay content of less than 20%. Also, the length of the perforations should not be too long, and for long perforation this process should be done in several stages. Eventually, no production reduction was observed in the imposed wells (Burger et al., 1986).

In Kern River field, California, U.S., also a modified furan resin is utilized which has the ability to remain stable up to 700 °F and can be used at almost any bottom-hole temperature. It is not environmentally harmful and has low cost. Also, the operation was successfully implemented in 95 wells, resulting in a 60% reduction in sand production and a remarkable reduction in the time the well was closed during injection; it can also be improved by optimizing the effective parameters (Fader et al., 1992).

According to the results obtained from the use of furan resin in a field in the Gulf of Mexico, it was found that resin application is an acceptable method for sand production control. This method seems to be more responsive in recently perforated wells, although this method was successfully used to workover wells, but there is a high risk of using this method for wells that are currently have sand production problem. It is also expected that using this method will cause a small amount of skin effect around the wellbore. The success of this method depends on the selected materials and operation performing method, it has been successful with the use of hydraulic displacement for 40 ft intervals (Parlar et al., 1998).

Organosilane was used at one of the North Sea oilfields to increase the maximum rate of sand-free production. Initially, using experimental investigations, among organosilane-based chemicals, polymer-based and enzyme based on calcium carbonate deposited (CaCO₃), organosilane-based chemical was selected for fulfilling in field operation. Of course, all three materials had sand-consolidating property, but the reason for choosing organosilane-based chemicals was that it had the best performance in terms of both consolidated sands strength and minimum permeability reduction. The chemical was used in three wells of this field and two potentials of this process, reducing sand production and increasing oil production, were evaluated. The results of which are summarized in Table 5 (Kotlar et al., 2005).

In another North Sea oil field, organosilane was used to control sand production. An important property of this chemical system is its solubility in oil, which does not alter the relative permeability of the oil pay zone and thereby reduces the risk of increased skin due to saturation changes and will also be useful in low-pressure oil reservoirs. This method was used in three wells in the mentioned oil field which one of them shows the oil production increment about 2000 sm³/day. There is also less disruption in the well's performance as the chemical is pumped directly into the formation and oil production resumes slowly about 6–9 h afterwards. However, in very deep wells, chemical fluid injection into the desired pay zone precisely is a difficult process. Tests have also shown that the use of organosilane can alter the rock wettability to preferentially neutral (Kotlar et al., 2006).

Organosilane is also used to control sand production in Heidrun

field in the Norwegian Sea (Haavind et al., 2008). In this case, the organosilane reacts with the connate water around the wellbore and forms a polymeric network and increases the strength between the formation sands that the byproduct of the reaction of organosilane with connate water is ethanol. So far, this chemical remedy has been used in three wells have of the field. The results of this operation indicate that the chemical method can be a good method for sand control if is performed in suitable wells. The performance of this method was reported as poor in a long horizontal well (A-45), good in a relatively short well (A-15) and excellent in a sub-sea well (E-1 BH).

The catalyzed epoxy resins usage in the gas field in the Mahakam Delta in Indonesia has been another case of chemical consolidation. In the gas field, this material has been used to control sand production and the results show that this method is a reliable method for fortification of the formation. The success of this method, however, depends entirely on the wells selected. For example, the formation intervals for injection should be between 10 and 15 ft and they should also have good permeability for the penetration of the resin-containing fluid. Most importantly, this material is used for a temperature range of 200–350 °F. In this method, instead of separately injecting the resin and the activating agent, the two materials are combined and then injected. This allows fluid to be injected at a pressure lower than the fracture pressure of the formation. The results of this case indicate that the selected wells were at temperature well below the upper limit of temperature, which increased the required time to reach the desired strength. Also, water production does not have a negative impact on sand production (Chaloupka et al., 2010).

Proppant-coated nanoparticles have been used in the Gulf of Mexico's marine wells to control sand production. In this case, nanoparticles have been used to consolidate sands because of their high surface forces. The wells that this method perform in those had free-sand production for 10 months (Huang et al., 2010).

The use of resin in the Tuna gas field in Malaysia has been another use of chemicals to control sand production. In this case, after laboratory experiment, resin consolidation method was applied to two wells of this gas field. In both wells, a mixture of the surfactant and diesel was used as preflush fluid and then main solution for sand consolidation was injected and eventually diesel fuel was used as overflush fluid. The results of this field operation show that in both wells, gas production increased by 0.5 MMscf/day (Fuller et al., 2011).

Another field study has been carried out in Peninsular field, Malaysia to control sand production by furan resin injection. In this field due to the sand production problem, many methods of sand production control, including well-cleaning from sands or using screens, have been accomplished, but there was still the sanding problem and so it was decided to focus on sand consolidation in the matrix. The challenge that exists in chemical injection methods is injecting the fluid into the desired layer in multilayer reservoirs that this is possible by using inflatable packers. The result of this operation was that before imposing this method, the production rate of the well was about 100 barrels per day (with a size of 60/64 inches), but after that the production rate of well increased for three months to 500 barrels per day (40/64-inch choke size) and

Table 5

Results of organosilane injection for sand production control in three wells at one of the North Sea oilfields (Kotlar et al., 2005).

Wells	Sand production	Oil production
#1	Mild sand production after two months	Increasing oil production by 1000–2000 sm ³ /day
#2	Decreasing sand production, sands strength lasted up to one month	First, a reduction of oil production by 300 sm ³ /day
#3	Sands strength lasted up to two weeks	Increasing oil production by 300 sm ³ /day

Table 6
Summary of chemicals used to control sand production in field research and operation.

Field location	Field status	Chemical(s)	Success/failure	Reason(s) for failure	Reservoir conditions	Literature
U.S.	Fields in South Louisiana	Phenol resin	75% success from 545 wells	Well conditions such as poor cementation	3600 psi 120 °C	Rike (1966)
U.S.	12 offshore cases 2 cases in Texas 1 case in Louisiana	Epoxy resin with low viscosity	11 of the 14 wells were successful	Two cases due to poor primary cementing	80,000 ppm salinity 4000–5000 psi 38–82 °C	Shaughnessy et al. (1978)
France	Permeability: 1 D Porosity: 30% Layer thickness: 30 m Lithology: limestone	Polymerized organic materials	Successful	–	3200–3400 psi 54 °C	Burger et al. (1986)
Romania	Permeability: 1.7 D Porosity: 32% Oil gravity: 16 °API Clay content: 5%	Polymerized organic materials	Successful	–	200,000 ppm salinity 4100 psi 80 °C	Burger et al. (1986)
U.S.	Location: California Permeability: 3 D Porosity: 35% Oil gravity: 13 °API Clay content: 3%	Polymerized organic materials	Successful	–	5200–5400 psi 98 °C	Burger et al. (1986)
U.S.	Kern River Field with heavy oil, high permeability and low reservoir pressure	Modified furan resin	Success in all 95 wells, 60% reduction in sand production	–	120,000 ppm salinity	Fader et al. (1992)
U.S.	5 gas wells in Gulf of Mexico	Furan resin	Successful in all 5 gas wells	–	Low pressure (not mentioned) 121 °C Not mentioned salinity	Fader et al. (1992)
North Sea	Permeability ranges from 50 mD to 1 D With water breakthrough	Organosilane	Well #1: mild sand production after 2 months Well #2: this method is effective for one month Well #3: this method is effective only for 2 weeks	Probably lower volume of injection fluid to wells 2 and 3 Water production may be due to incorrect chemical exposure and relative permeability change	2676 psi 145–190 °F Not mentioned salinity	Parlar et al. (1998)
North Sea	Permeability ranges from 50 mD to 1 D With water breakthrough	Organosilane	Sand production continued in 1 well of 3 wells	Non-injection of fluid to all the desired layer due to pressure difference between the layers or the production of sand from another layer	Not mentioned pressure and temperature of the field	Kotlar et al. (2005)
Indonesia	Location: Mahakam Delta gas field Well #2 and 3 with permeability 2 D and porosity 25% Well #3 with 35 mD permeability and porosity 20%	Catalyzed epoxy resin	All three wells were free of sand for four months after fluid injection	–	3500–37000 psi 79 °C	Haavind et al. (2008)
Malaysia	Location: Tono gas field Horizontal permeability: 1 D Porosity: 28% Clay content: 25%	Resin	It was successful in both wells	–	140,000 ppm salinity 3300 psi	Chaloupka et al. (2010)
Malaysia	Permeability: 120 mD Porosity: 22% Thickness: 17 m	Furan resin	Successful	–	93–177 °C	80,000 ppm salinity
Malaysia	Permeability: 120 mD Porosity: 22% Thickness: 17 m	Furan resin	Successful	–	1500 psi 74 °C	Fuller et al. (2011)
Malaysia	Permeability: 120 mD Porosity: 22% Thickness: 17 m	Furan resin	Successful	–	Not mentioned salinity 2450 psi 93–149 °C	Keith et al. (2013)
Malaysia	Permeability: 120 mD Porosity: 22% Thickness: 17 m	Furan resin	Successful	–	125,000 ppm salinity	

then stabilized at the rate of 350 barrels per day (55/64-inch choke size). A key to the success of this operation was the use of inflatable packer and optical fiber in the coil tubing, which allowed the chemical fluid to be injected into the targeted layer. Moreover, the inflatable packer eliminated the risk of resin spilling out into the micro annulus between the coil tubing and the production tubing when plugging the coil tubing and the production tubing once it hardens. In general, the success of this method in multilayer reservoirs depends on how the fluid is injected and delivered to the desired layer and the correct application of the method (Keith et al., 2013).

In the Nile Delta field, water-base resin was used to control sand

production. The reason for using water-base resin was that the commonly used resins sometimes did not respond in long intervals. Also, because of low diameter (5 inches) of the well in this field, it was not possible to use gravel pack. After using this method, the amount of produced sand during the production with a 28/64-inch choke was reduced from 80 kg/day to about 4 kg/day. The wellhead pressure also increased to about 45 psi compared to before the sand control (Songire et al., 2014).

The use of water-based resin in one of the fields in eastern Malaysia is another field study to control or alleviate sand production. Unlike solvent-based resins that have low flash point (about 100 °F), water-resin flash point is about 235 °F, which

Table 7

Requirements for chemical injection process to control sand production (Aggour et al., 2007; Burger et al., 1986; Chaloupka et al., 2010; Fader et al., 1992; Fitzgerald et al., 1966; Fuller et al., 2011; Haavind et al., 2008; Huang et al., 2010; Keith et al., 2013; Kotlar et al., 2005, 2006; Parlar et al., 1998; Penberthy and Shaughnessy, 1992; Rike, 1966; Riyanto et al., 2016; Shaughnessy et al., 1978; Songire et al., 2014).

Requirements	Description
Reservoir and near wellbore region temperature interval	The temperature range depends on the chemical used, most resins are effective and applicable in the range of 200–350 °F.
Permeability of the layers around the well	The selected interval must be slightly thick so that the resin can be applied to all sands, the optimum thickness is estimated to be between 5 and 25 ft.
Utilized tools in well completion	The permeability of this section should be as homogeneous as possible; existing a high and low permeable layer in a pay zone causes most resins enter the high permeable layer and the problem of the low permeable layer is not resolved.
Sand production history	The less well completion tools like screen in the well, the better penetration of the resin into the layer and better sands consolidation.
Oil/gas production history	The likelihood of success of this technique in newly perforated wells is higher than in wells with a history of sand production. It is advisable to use this method for reservoirs with no more than two years of production.

Table 8

Stages of chemical injection operation for sand consolidation.

Stages	Purposes	Literature		
		Parlar et al. (1998)	Chaloupka et al. (2010)	Riyanto et al. (2016)
Acid injection	Perforation cleaning	Injecting NH ₄ Cl (3%)	Not doing	Unknown
	Damage removal around the wellbore	Injecting HCl		
	Clay particle elimination	Injecting HCl–HF		
	Reservoir fluid displacement	Injecting HCl (5%) Injecting NH ₄ Cl water-based solution		
Preflush surfactant injection	Removing acid from around the well	Injecting NH ₄ Cl	Injecting diesel + surfactant	Injecting KCl water-based solution + foam as diverter
Resin/chemical injection	Wettability alteration of sands to oil-wet Sand coating by resin	Injecting furan resin	Injecting catalyzed epoxy resin	Injecting water-based resin
Displacement fluid injection	Displacement of excess resin/chemical in pores	Injecting HEC fluid	Injecting diesel	Injecting KCl water-based solution
Acid catalyst overflush	Initiation of polymerization of the resin and its hardening	Injecting HCl (15%) Injecting HCl containing NaCl in saturated water Injecting HCl containing NaCl in unsaturated water	Unknown	Injecting KCl water-based solution
Well shut-off	Provide enough time for sand consolidation	16 h	Unknown	3 days

provides greater safety. Solvent-based resins can also be injected in small intervals, but water-based solvents can be used in longer intervals. By testing this method in this field, it was perceived that it had more efficient in controlling or mitigating sand production than traditional resin injection methods (Riyanto et al., 2016). Finally, Table 6 summarizes some field research and operations using chemicals with regard to the success or failure of these projects with possible reasons and other details. Furthermore, by scrutinizing the field reports of sand control by injection of resins and chemicals, the requirements for these operations are presented in Table 7.

According to Table 6, it can be said that most of the field operations have been carried out in order to control sand production by chemical methods using resins. This shows that despite the development of different novel chemical methods that were introduced in Section 3, the use of resin is still recognized and used as the most accepted method in the industry. This is due to the low financial and operational risk of using resins compared to other modern methods. Therefore, other novel laboratory methods need to be approved in the pilot section so that they can be used in the industry. Also, the use of different resins in different pressure conditions (pressure, temperature, formation water salinity) indicates that the resins have good resistance in reservoir conditions and have worked successfully. Another noteworthy point that can be seen in Table 6 is the high permeability of most of the cases in which chemical injection was fulfilled. Because if the permeability of the formation is low, it is possible that if chemicals are injected to

control the sand production, the permeability will decrease drastically, which will cause a significant decrease in production from the reservoir. Finally, it can be said that according to the reported operational conditions, choosing the right chemical substance according to the conditions of the reservoir will be a vital issue in the chemical control of sand production.

The chemical injection operation to consolidated loosely sand has six stages, including acid injection, injection of preflush surfactant, resin/chemical injection, displacement fluid injection, acid catalyst overflush and well shut-off for a specific time. Table 8 epitomizes the stages of these operations, with performed field operations and the purposes for each step.

6. Conclusions

Chemical remedy of sand consolidation is an effective and economic method for controlling sand production in oil and gas industrial. In this paper, the research, both laboratory and field investigations, on chemical treatment techniques for *in-situ* sand consolidation has been overviewed, and also details of used chemicals, most common laboratory test in this area, field experiments and steps of chemical injection are discussed. It can be concluded from the studies that advantages of using chemical material such as resins, are easier applying, more affordable and more effective than other methods (mechanical and restrictive methods) of sand production control. On the other hand, one of the most important disadvantages of this technique is the possibility of

permeability reduction of the area around the wellbore dramatically. Also, if the viscosity of the injecting fluid which contains chemical is high, it can cause to frack the formation. It is important to note that a significant change in permeability after injection of a chemical composition is not the only requirement. The injection of chemical reagents is very dependent on the possibility of absorption of the chemicals to the surface of the rock, the possibility of uniform distribution of the chemicals within the medium of the reservoir, on the small radius of treatment of the bottom-hole zone of the formation, the need to re-treat of the reservoir after a short period of time due to the washing out of the injected composition. Moreover, if the candidate reservoir for chemical treatment is multilayer with different properties (porosity, permeability, wettability, etc.), injecting the fluid into the targeted layer requires specific procedures. To implement this method on a field scale, the steps of injecting chemicals into the formation including acid injection, injection of preflush surfactant, resin/chemical injection, displacement fluid injection, acid catalyst overflush and well shut-off for a specific time must be carefully fulfilled. Of course, a successful operation design requires accurate estimates and predictions, which can be accomplished by applying modeling and simulation of sand production. Finally, it should be noted that according to field operation reports, chemical remedy for sand production control is more effective in newly perforated wells which have no sand production experience and have a production history of less than two years.

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