A Critical Review on Sand Production Prediction methods and Mitigation for Chemical Enhanced Oil Recovery (CEOR) Wells

By:

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15012

Dissertation in partial fulfillment of

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the

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(Petroleum)

Approved by,

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(Noor Ilyana Ismail)

Universiti Teknologi PETRONAS

TRONOH PERAK

January 2015

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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(FARAH NURDIANA MOHD RAPOR)

ABSTRACT

Recovery is the heart of hydrocarbon production from underground reservoirs. There are basically three phases of recovery in a life of a reservoir which are primary, secondary and tertiary phase which in other words are also known as the enhanced oil recovery (EOR). Most of studies showed that only 20-30% of the reservoir sources are recovered during the first two stages but modern EOR technique can reach up to 70% (Tunio, Tunio, Ghirano, & El Adaqy, 2011). There are also a few methods and technology available in conducting EOR process. One of it is by applying chemical EOR (CEOR) method. The main purpose of applying EOR technique is to increase the production of oil as there is a higher demand while supplies are reducing (Tunio et al., 2011). However, production of sand during chemical EOR operation will reduce the production target that is aimed to achieve. Thus, the objectives of doing this project are to determine factors that caused sand production during CEOR operation, to review current sand production prediction method available to predict sand production for CEOR wells applications and to review latest sand control technologies that can be applied for mitigation of sand production in CEOR wells. As this is a research based project, thus the methodology is divided into three parts which are i) doing an extensive literature review and critical analysis regarding the topic, ii) constructing a root-cause analysis diagram (Ishikawa Diagram) on factors that cause sand production and iii) studying available sand prediction method as well as reviewing latest sand control technologies available for CEOR wells applications. At the end of this project, a summary of all the objectives will be presented.

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INTRODUCTION

1.1 Background

Enhanced oil recovery indicates the process of producing liquid hydrocarbons by other methods than reservoir re-pressurizing schemes with water or gas and by conventional use of reservoir. Moderately, conventional production methods usually produce about 30% of the initial oil in place from the reservoir and that leaves about nearly 70% of the initial resource. This value indicates that there is still a large and attractive target for the application of recovery methods (Terry, 2000).

The main aim of enhanced oil recovery operation is to increase the production of hydrocarbon. However, there are some problems that might occur along the way. One of the problems encountered in chemically enhanced oil recovery operations is well degradation due to co-production of sand formation along with the oil. Sand production is a serious problem and a major concern in oil and gas industry globally. It can aggressively affect production rates; it can damage downhole and surface facilities and also subsea equipment leading to catastrophic failure and costing operators billions of dollars annually. All of these problems will negate the main purpose of recovery of a reservoir.

Some of the factors that cause sand production are poorly consolidated and unconsolidated sand formation, reduction of pore pressure, increasing water production and reservoir fluid viscosity. All of these factors are prone to occur even during recovery stages. The main focus of this project is to predict and mitigate sand production during chemical EOR operation. Based on the study, there are not many methods and technology available in the industry to predict sand production in wells that are undergoing chemical recovery. It is important to predict sand production during EOR to achieve its main purpose to maximize hydrocarbon production. Other than that, this project will also review latest sand control technologies for chemical EOR wells.

1.2 Problem Statement

EOR's main objective is to increase production rate of a reservoir. Sand production causes many adverse effects to the reservoir, wells and also equipment. It is believed that there is yet to be a proper guideline on how to predict sand production and also its mitigation during enhanced oil recovery operations in the industry. This is a concerning issue as sand production will negate the main objective of recovery operation of a reservoir. Based on studies, it is found that there is a lacking of guideline on specific method for predicting sand during CEOR operation and also available technology for mitigation of sand that can be applied in CEOR wells. Thus, the main objective of doing this project is to find a solution to this problem through extensive literature review on sand production prediction and latest sand control technologies for EOR wells.

1.3 Objectives

- To identify factors that cause sand production during chemical enhanced oil recovery (CEOR) operation.
- To review available sand production prediction methods.
- To review latest sand control technologies for chemical EOR wells application.

1.4 Scope of Study

During this project, the author will first conduct a research on factors of sanding during chemical enhanced oil recovery (CEOR) operations. After identifying the factors, the author will proceed with review on current sand production prediction methods and latest sand control technologies for this type of wells. At the end of the study, the author will come out with summaries on the methods and technologies available based on the details review.

1.5 Relevancy and Feasibility

In hope of a successful findings and analysis of the objectives, this research project will give some benefits to the industry as the guideline on sand management issue. This project is feasible to be carried out by considering the capability of final year student and time constraint with the assistance of supervisor. May this project becomes successful and can be completed within the timeframe.

CHAPTER 2

LITERATURE REVIEW

2.1 Enhanced Oil Recovery

Oil production of a reservoir is divided into three phases namely; primary, secondary and tertiary which is also known as Enhanced Oil Recovery (EOR). These three recovery phases follow a natural progression of oil production from the start to a point where it is no longer economical to produce from the hydrocarbon reservoir. Based on U.S Department of Energy, amid primary recovery, the driving mechanism that drives the oil into wellbore is the gravity or natural pressure of the reservoir. The combination with artificial lift techniques, for example by utilizing pump jacks help push the oil to the surface. However, this technique will only cover 10% of the total production of reservoir's original oil in place.

Secondary recovery is ordinarily used when the primary production decreases. The techniques that are usually used during this operation are gas injection, water flooding, and pressure maintenance (Terry, 2000). These two recovery process are called conventional recovery and its targets mobile oil in the reservoir (Kokal & Al-Kaabi, 2010). U.S Department of Energy also mentioned that these two phases of production leaves a remaining of 75% of oil in the reservoir.

As an effort to further increase the production of oil in a reservoir, a tertiary recovery is applied. Enhanced recovery plays a progressively more important role in oil production. Enhanced Oil Recovery can be defined as a reduction of oil saturation below the residual oil saturation. An approach of lowering the oil saturation below S_{or} can cause high viscosity oils such as heavy oils and tar sands that are immobile and also oils that are retained by capillary forces (after a waterflood in light oil reservoirs) to be recovered (Thomas, 2008). Generally, Enhanced Oil Recovery processes include all techniques that utilize foreign sources of energy and/or materials to recover oil that cannot be produced by conventional methods (Barrufet, 2001).

The purpose of EOR processes is to increase the pressure difference between the production wells and the reservoir, by reducing the viscosity of oil to increase the oil mobility or reduction of interfacial tension between oil and displacing fluid (Sultan Pwaga, 2010). There are 3 major categories of Enhanced Oil Recovery technologies that are considered to be promising. Those methods are including thermal recovery, miscible gas injection and chemical flooding.

Thermal EOR methods are customarily applicable to viscous, heavy crudes. This method introduces heat or thermal energy into the reservoir by reducing the viscosity of oil with the increase in temperature (Kokal & Al-Kaabi, 2010). Steam or hot water is usually used as the hot fluid to be injected into the wells. Three sorts of procedures that are usually used in this method are in-situ combustion, steam drive and steam cycling (Terry, 2000).

Gas injection, which is considered as the oldest in enhanced oil recovery method, is one of the most promising EOR technology (Taber, Martin, & Seright, 1997). This method utilizes gases such as natural gas, carbon dioxide (CO2) and nitrogen. These gases expand in reservoir to push oil to a production wellbore. Some other gases that dissolve oil can also be used to improve oil flowrate and also reduce its viscosity.

Meanwhile, the essential objective of chemical recovery or chemical flooding is to recover more with the use of long chained molecules called polymers to increase the effectiveness of waterfloods. The application detergent-like surfactants that are used in this method helps in reducing the surface tension that usually reduce the mobility of oil throughout the reservoir. This method helps to improve sweep efficiency in the reservoir (Terry, 2000). Surfactant flooding is considered as the fundamental of chemical process. It acts as the key mechanism in reducing the interfacial tension (IFT) between displacing fluid and the oil. The mechanism, because of the reduced IFT, is correlated with the increased capillary number, which is a dimensionless ratio of viscous to local capillary forces (Sheng, 2010).

2.1.1 Chemical EOR Technology

In this project, the author will focus on only one category of enhanced oil recovery which is the one that is applying chemical technique. There are three major chemical flood processes and they are surfactant flooding, polymer flooding and alkaline flooding. There are also other methods that has been tested and that include emulsion, foam and utilization of microbes. However, the impact of applying these methods has not been significant on enhanced oil recovery thus far (Thomas, 2008).

2.1.1.1 Surfactant Flooding

Surfactants are effective in reducing the interfacial tension between water and oil. The purpose of applying surfactant flooding is to recover the capillary-trapped residual oil after waterflooding. With the injection of surfactant solutions, the mobility of residual oil will be improved as the interfacial tensions between oil and water has now been reduced. Generally, petroleum sulfonates or other commercial surfactants are utilized (Thomas, 2008). The objective of this process is basically to inject a slug of surface active material that has the capability to mobilize residual oil that can be produced and displaced. Surfactant slug that represents only a small amount of the total pore volume, is driven through the reservoir by a subsequent slug of thickened water (polymer solution), which later will be displaced by brine or water. The mobility of each of these slugs are altered to improve the volumetric coverage of the process and also to minimize channeling and bypassing (Shah, 1977).

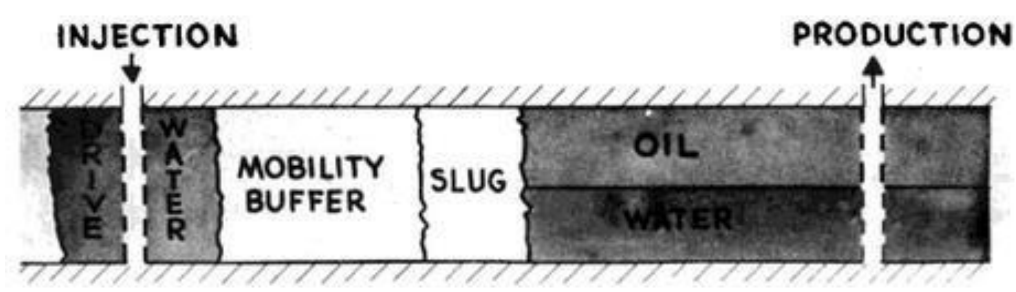


FIGURE 1: Surfactant Flood (Shah, 1977)

2.1.1.2 Polymer flooding

Polymers are used to help in obtaining favorable mobility ratios during water or surfactant flooding. During flooding period, the viscosity of the polymer solution should not be reduced. Temperature can affect polymer viscosity both with respect to the dependency of chemical breakdown of the polymer chain on temperature and the change in state of energy. The high viscosity of the polymer solution will lower the injectivity drastically and causing a low injection rates. Polymer solution is injected in surfactant flood to help achieving better volumetric sweep of the reservoir. The same purpose was aimed during the injection of polymer solution in conjunction with a water flood. This is illustrated in Figure 2. The intention is that water will be forced to flow through more flow channels in the rock by the reduction of mobility of the water, (Shah, 1977). Commonly, combination of surfactant and polymer flooding will results in the increment of water viscosity and reduction in relative permeability to water. Water soluble polymers, such as polysaccharides and polyacrylamides are effective in reducing permeability contrast and producing an improved mobility ratio. Generally, polymer flooding is applied as a slug process and is driven using dilute brine. The concentration of the polymer is usually between 200-2000ppm (Chang, 1988).

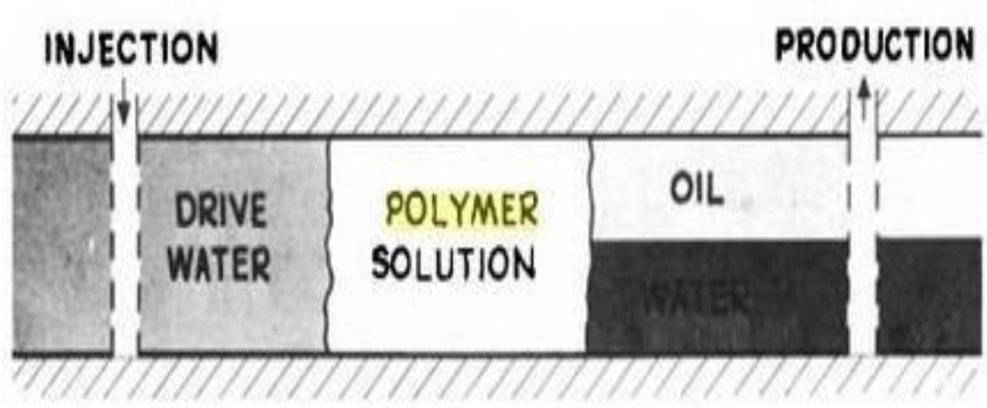


FIGURE 2: Polymer Flood (Shah, 1977)

2.1.1.3 Alkaline Flooding

Alkaline solutions also are being used as pre-flushes in micellar/polymer projects. Alkaline oil recovery has been attributed to oil/alkali interaction which is called emulsification, wettability alteration between the alkaline solution and the rock and chemical precipitation caused by mixing of the injected alkaline solution with the hardness ions in brines (Mayer, Berg, Carmichael, & Weinbrandt, 1983). In alkaline or caustic flooding, a slug of water that contains caustic is injected into the reservoir and followed by brine or water (Figure 3) (Shah, 1977). An aqueous solution of an alkaline chemical, such as orthosilicate of sodium, carbonate or hydroxide is injected in a slug (Thomas, 2008). Most field projects to date have used sodium hydroxide. Sodium orthosilicate is used because it forms very insoluble products with divalent ions such as calcium and magnesium. These divalent ions reduce the degree to which interfacial tension (IFT) is lowered. IFT reduction is the key mechanism of the fluid/fluid interaction. Natural acid associated with some crude oils are neutralized with the injected caustic and become surfactants. These surfactants concentrate at the oil/water interface and lower the IFT. With time, the surfactant will migrate into the water phase and speeded up as the concentration of surfactant in the brine is lowered (Gogarty, 1983). Spontaneous emulsification may occur. Drop entrapment or drop entrainment might also take place depending on the type of emulsion formed, which might either enhance or decline the recovery.

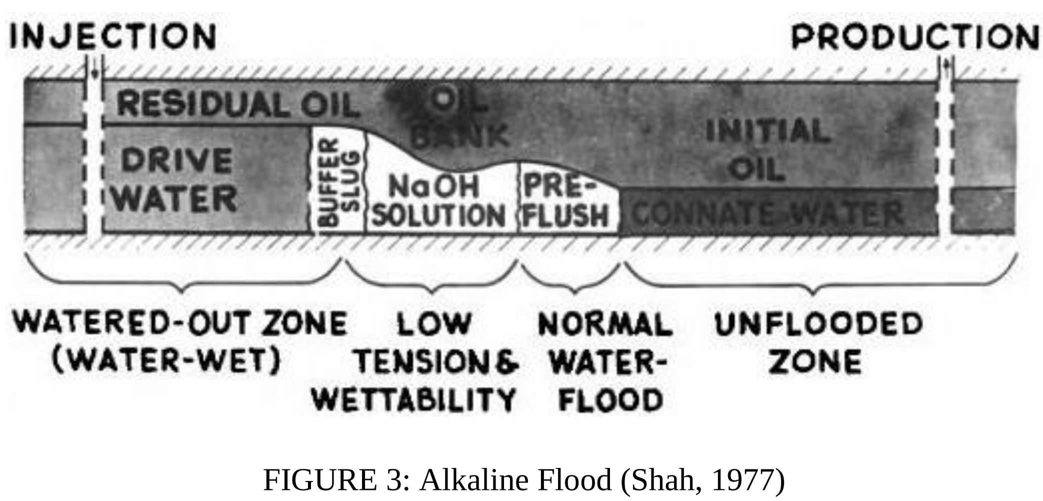


FIGURE 3: Alkaline Flood (Shah, 1977)

The current issue that is concerning is the production of sand during recovery operations as in this case, during chemical recovery. There are many factors that can cause sand production in a reservoir. Sand accumulation can adversely affect the integrity of process facilities and also causing impairment and more importantly, it decreases the production which is in this case, reduction of production rate negates the main purpose of enhanced oil recovery.

2.2 Sand Production

Sand production or sanding is the production of the formation sand alongside with the formation fluids (gas, oil and water) due to unconsolidated nature of the formation (Mohamed, Lesor, Aribo, & Umeleuma, 2012). Sand accumulation is a serious problem in oil and gas industry globally. It can aggressively influenced production rates, damage surface and downhole facilities and costing producers tens of thousands billion dollars annually. This problem is one of the continuing issues that burden the oil and gas industry because of its economics, safety or environmental impact on production (Nouri, Vaziri, Belhaj, & Islam, 2003).

Many researches over the years have researched the causes of sand production and searched for the reliable means to predict it. Sand production prediction is important because of the operational, safety and environmental concerns involved when accumulated sand particles fill and plug the wellbore, causing erosion to the equipment and raise the operational cost of production and maintenance (Moore, 1994). This problem becomes a more concerning issue especially when it happens during recovery operations. The production of sand will defeat the purpose of recovery by reducing the production of hydrocarbons.

2.2.1 Factors Causing Sand Production

Based on researches and studies made by the author, there are some factors that affects the tendency of well to produce sand. They can be summarized as these:

i. Degree of consolidation:

- Poorly consolidated or unconsolidated formations are prone to experience sanding. According to Carlson J. et al, unconsolidated sandstone reservoirs that have permeability of 0.5 to 8darcies are more inclined to produce sand.

ii. Reduction in pore pressure during the life of a well

- As the reservoir pressure is depleted, some of the support of the overlying rock is detached and it brings about an increasing amount of stress and formation sand itself (Zhang, Rai, & Sondergeld, 1998). At some point, the formation sand grains may break loose from the matrix and creating fines that are produced with the well fluid.

iii. Increasing water production

- Sand production may begin or increase as water begins to produce as water cut increases. All the three methods of chemical injection; surfactant flooding, polymer flooding and alkaline flooding is followed by the injection of water or brine. Thus considerable amount of water is produced during this operation (Smith, 1988).

iv. Production rate

- Mohammed, A. et al. (2012), mentioned in his article that every reservoir has a threshold pressure at which a well will produce sand free. But this threshold pressure is below economic production rate; therefore the engineer tends to ignore the threshold pressure so as to produce at a maximum rate from a sandstone reservoir which then leads to sanding to occur.

v. Reservoir fluid viscosity

- High reservoir fluid viscosity results in higher frictional drag force to the formation sand grains compared to reservoir fluid that has low viscosity. Effects of viscous drag will results in sand production from heavy oil reservoirs in which it contains high viscosity, low gravity oils even at low flow velocities.

Based on the points summarized above, it can be concluded that these factors are also prone to occur during chemical recovery. The chemical compositions that are injected in the reservoir might contain toxic that is not compatible with the formation.

Reservoir lithology is one of the screening considerations for EOR methods, usually limits the capability of specific EOR methods. Based on study made by Alvrado, V. et al, most EOR applications have been in sandstone reservoirs. From Figure 4, it is obvious that chemical and EOR thermal projects are the most frequently utilized in sandstone reservoirs in comparison to other lithologies (e.g., turbiditic and carbonated formations) (Alvarado & Manrique, 2010).

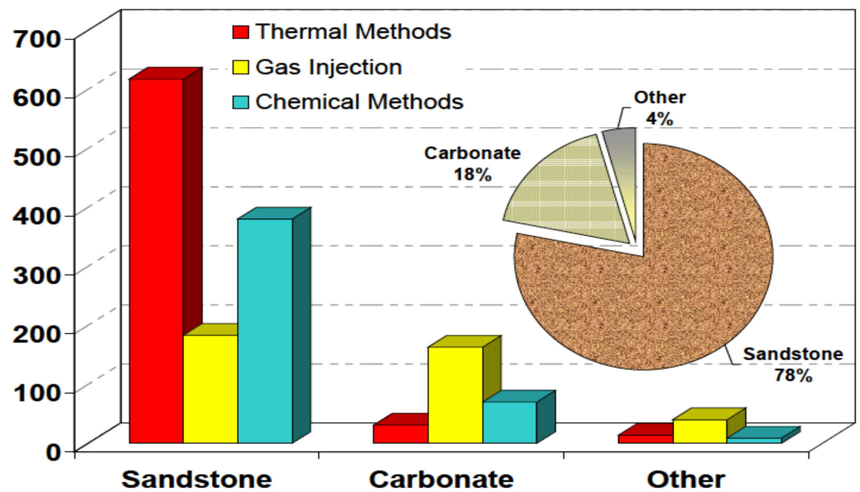


FIGURE 4: EOR methods by lithology (based on a total of 1507 projects) (Alvarado & Manrique, 2010)

Sand production happened when the induced in situ stresses exceed the formation in-situ strength (M. Al-Awad & Desouky, 1997). Based on this strength, the sandstone formation can be classified as unconsolidated, competent and weak. For competent sandstone formation, sand production happened because of the shear failure, which occurs on the surface of the rock (i.e. borehole surface) due to high shear stress. During production, the induced shear failure surfaces are mobilized and sand debris is produced due to drag forces caused by the reservoir fluid flow. The produced sand will then flow into the well along with the reservoir fluids (M. N. Al-Awad, 1997). In unconsolidated and weak formations, production occurs when the drag forces caused by the flowing reservoir fluids overcome the natural inherent cohesion of the formation (M. N. Al-Awad, 2001).

Based on the review of full field case histories, polymer flooding is still the most important EOR chemical method and is considered a mature technology in sandstone reservoirs (Alvarado & Manrique, 2010). As indicated by EOR survey presented by Moritis in 2008, there are a large scale polymer floods in Argentina (El Tordillo Field), Canada (Pelican Lake), China with approximately 20 projects (e.g., Daqing, Gudao, Gudong and Karamay fields, among others), India (Jhalora Field) and the U.S. (North Burbank, Oklahoma).

While polymer flooding has been the most applied EOR chemical method in sandstone reservoirs, the injection of alkali, surfactant, alkali-polymer (AP), surfactant-polymer (SP) and Alkali-Surfactant-Polymer (ASP) have been tested in a limited number of fields (Alvarado & Manrique, 2010). Micellar polymer flooding had been ranked as the second most applied EOR chemical method in medium and light crude oil reservoirs until the early 1990's (Lowry, Ferrell, & Dauben, 1986). Even though this technology was considered a promising EOR process since the 1970's, the high cost and concentrations of surfactants and co-surfactants, combined with the low oil prices during mid-1980's act as a limiting factor of the usage of this chemical solutions. The development of the ASP technology since mid-1980's and the development of the surfactant chemistry have rekindled a renewed consideration for chemical floods in recent years, specifically to increase oil production in waterflooded and mature fields (Alvarado & Manrique, 2010). All of these fields are sandstone reservoir type and are applying polymer-flooding as their EOR method. Thus, sand production is prone to occur in these fields.

Furthermore, increase in water-cut in the reservoir formation during late life of reservoir is unavoidable, be it because of water injection or water coning (B Wu & Tan, 2001). As EOR is applied after the first and secondary recovery of a reservoir, the field is considered to be in the late life as it has already been produced for a few years. Generally, each barrel of oil that are produced by oil companies today represents three barrels of (Bailey et al., 2000). As mentioned above, chemical injection during recovery is followed by the injection of water/brine. This will increase the water-cut and minimize the capillary pressure that exists between the water and the capillary fluid, and rock strength (B Wu & Tan, 2001).

The consequence of water-cut on sand production has been a major concern in oil and gas industry. It has been seen in numerous events in the field that initiation of sand production coincides with water breakthrough (Veeken, Davies, Kenter, & Kooijman, 1991). The effect of water cut on sand production has been an area of research for a number of years, and a number of mechanisms have been hypothesized to explain the effect (Bianco & Halleck, 2001; Hall Jr & Harrisberger, 1970; Han & Dusseault, 2002; Skjaerstein, Tronvoll, Santarelli, & Joranson, 1997; Vaziri, Barree, Xiao, Palmer, & Kutas, 2002; Willson, Moschovidis, Cameron, & Palmer, 2002). The summary of the hypothesis made regarding the relations of water cut and sand production are listed below:

- Capillary-bonding reduction between originally water-wet sand grain
- Chemical interaction between rock matrix and water because of increase in water saturation
- Relative permeability effect resulting in an increase drag force for mobilizing sand grains from failed sand materials

The chemical interactions between sandstone at in-situ condition are considered to be in a state of chemical equilibrium with formation water. Water breakthrough adjusts the equilibrium due to the difference in chemical composition of the invading water. Chemical reactions will take place to reach a new equilibrium (Bailin Wu, Tan, & Lu, 2006). Possible chemical reaction includes clay swelling, carbonate dissolution, and quartz hydrolysis (Han & Dusseault, 2002). The surface of clay platelets carries the negative charges and results in clay swelling. These chargers can attract layers of water molecules because the water molecules are dipolar. Other than that, the cations present in the free water are not strongly attached to the clay particles, and if the composition of the water changes, they can be replaced by other cations – a phenomenon that is called cation exchange. Furthermore, the exchangeable cations can attract water and become hydrated. Among the three basic clay minerals, smectite has more affinity for water compared to illite and kaolinite. Due to its large surface area and weak bond between platelets, considerable swelling of smectite is prone to happen because of hydration.

2.2.2 Sand Prediction

There are basically three techniques to predict sand production. They are either based field observation data of sand production, laboratory experiments or theoretical modeling.

2.2.2.1 Field Observation of Sand Production

This technique relies on the establishment of correlation between sand production well data and field operation parameters. The parameter that triggers the production of sand is tabulated in the table below. However, among all these parameters, only small selections are going to be used. This is due to the practical difficulties of monitoring and recording several years' worth of data for all the wells involved in a study.

TABLE 1: Parameters influenced by sand production (Veeken et al., 1991)

FORMATION	Rock • Strength • Vertical and horizontal in-situ stresses (change during depletion) • Depth (influences strength, stresses and pressures) Reservoir • Far field pore pressure (changes during depletion) • Permeability • Fluid composition (gas, oil, water) • Drainage radius • Reservoir thickness
COMPLETION	• Wellbore orientation, wellbore diameter • Completion type (open hole/cased hole) • Sand control (screen, gravel pack, chemical consolidation) • Size of tubulars

PRODUCTION	• Flowrate • Drawdown pressure • Flow velocity • Damage (skin) • Bean-up/shut-in policy • Artificial lift technique • Depletion • Water/gas coning • Cumulative sand volume

The influences of these parameters can be measured in three ways; one parameter, two parameters, and multi-parameters.

i. <u>One parameter</u>

- For this part, the prediction tool only uses one parameter

  Example: cut-off depth criteria.

- Based on Tixier, M (1985) and Lantz, J (1991), the critical cut-off depth is 12000 and 7000ft respectively. Sand control is not installed below this depth. This is however are dependent on the regional environment of the field. Another criterion that is considered in measuring the critical cut-off depth is by measuring the compressional sonic wave transit time. (Δt_c). In the research, the author mentioned that the limit Δt_c is again field or regionally dependent and may vary from 90 to 120μs/ft. Moreover, Tixier et al. also mentioned that a limit value of sonic and density log derived parameter was established (Lantz & Ali, 1991; Tixier, Loveless, & Anderson, 1975).

$$\frac{G}{c_b} = \frac{dynamic\ shear\ modulus}{bulk\ compressibility}$$

He found that sand production will not occur at a value of G/c_b exceeding $0.8*10^{12}psi^2$. This limit value has been successfully applied but as mentioned before, it depends on the regional environment (Coates & Denoo, 1981).

- The criteria specifying critical depth, Δt_c and G/c_b are related. For example, Δt_c decreases as depth increases; thus, the Δt_c criterion can be translated into a depth criterion and vice versa.
- Also, G/c_b =0.8*10psi^2 typically corresponds to Δt_c =115-120μs/ft. The one-parameter approach is practical, though conservative, and frequently used due to its ease of use (Tixier et al., 1975).

ii. <u>Two parameters</u>

- This prediction model include the depletion reservoir pressure (P_{de}) and drawdown pressure (P_{dd})
- Figure below shows the illustration of petrophysical tools of the two parameters model.

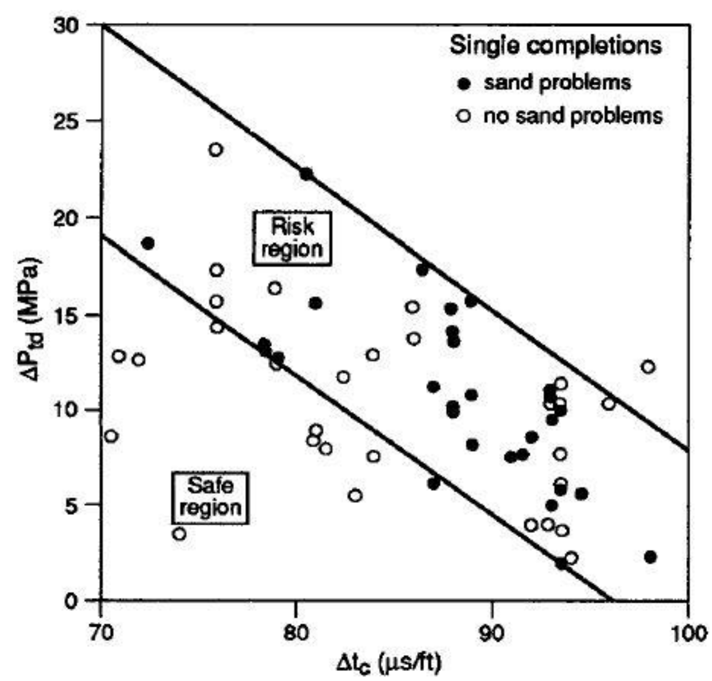


FIGURE 5: Total drawdown versus transit time for intervals with and without sand problems (Kooijman, Kenter, Davies, & Veeken, 1991)

- In Figure 5, the total drawdown pressure ($P_{td} = \Delta P_{de} + \Delta P_{dd}$) is plotted versus the sonic transit time for sand and no sand producing wells located in the same oil field.
- A risk region is with a slope of -0.74 MPa/(μs/ft) was established on the basis of data from several fields.
- Sand free production can be concluded to be on the left side of the risk region
- Figure 5 indicates that the increment of drawdown pressure will trigger sand production.
- The position of the risk region is field dependent; sand production tests or routine monitoring can be used to determine its position (Kooijman et al., 1991).

iii. <u>Multi-parameter</u>

- Multi-parameter correlations can improve the resolution between sand and no sand producer.

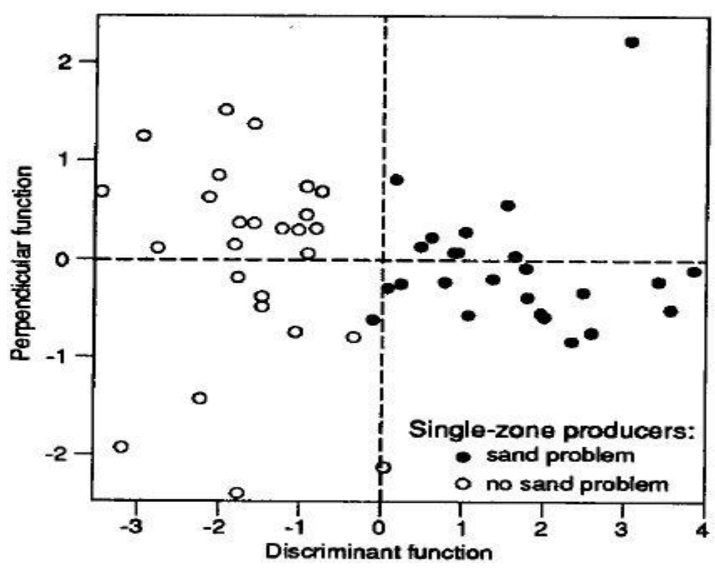


FIGURE 6: Plot showing result of multiple-discriminant analysis (Kooijman et al., 1991)

- Figure 6 illustrates the use of the multiple discriminant analysis technique for the data set of figure 5.

- Sand production is correlated with a wide range of parameters including depth, sonic transit time, production rate, drawdown pressure, productivity index, shaliness, water and gas cut.
- The sand and no-sand producing wells are well separated. The parameter influencing sand production most in case of Fig. 6 is water cut.
- Sand and no sand producers are characterized by an average water cut of 19% and 2% respectively. The discriminant function describing the influence of the various factors is regionally dependent.
- In a similar analysis, Alcocer, C. F (1989) used multiple linear regression to correlate the critical drawdown pressure observed in water-producing gas wells with seven parameters.
- The multi-parameter techniques are not commonly used because of the extensive data requirements.

2.2.2.2 Laboratory Sand Production Experiments

- Observe and simulate sand production in a controlled environment
- Helps develop insight into sand production mechanisms and influence of the various field and operational parameters on sand production
- Compare with theoretical model and validate
- Can be used as sand prediction tool after translation of the test results to the field situation (Kooijman et al., 1991).
- Carried out using both unconsolidated sand, and friable-consolidated sandstone.

TABLE 2: Factors causing sand production in different types of formation

Unconsolidated sand	Friable-consolidated sandstone
▪ Sand production dominated by flow rate and capillary forces ▪ Create cavity which gradually enlarge with flow rate and collapses at a critical flow rate.	• sand production and cavity enlargement is governed to a large degree by the boundary stress

▪ The flow rate corresponding to cavity failure is about 5-10 bpd (Kooijman et al., 1991) and relatively independent of: ➢ sand mixture, ➢ cavity size ➢ boundary stress ➢ pore pressure	

A simplified model test using thick walled cylinder sample has been developed for field application based on sand production test carried out on hollow cylinder sample.

2.2.2.2.1 Thick-walled cylinder approach

- This technique uses a hollow cylinder core sample. The assumption made is that the initial failure of a perforation can be related to the initial failure of a hollow cylinder core sample.
- Maximum near wellbore vertical effective stress ($\sigma_{v,w}$) sustained by a horizontal perforation is equal to initial failure pressure of a representative thick walled cylinder ($\sigma_{twc,i}$) which corresponds to the visual damage of the inner wall.

$$\sigma_{v,w} = \sigma_{twc,i} \quad \textbf{(1a)}$$

- The standard dimension of the thick walled cylinder are as follows:
  - ➢ Inner diameter: 25mm
  - ➢ Outer diameter: 8.5mm
  - ➢ Length: 50mm

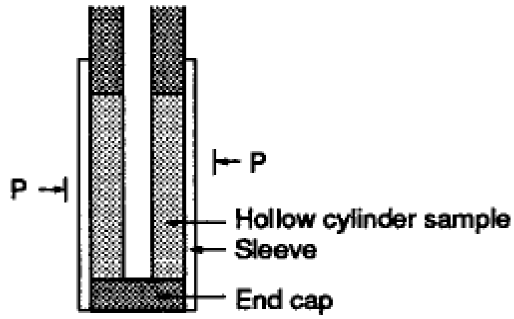


FIGURE 7: Test configuration (Kooijman et al., 1991)

- The near wellbore vertical effective stress is rather arbitrary and defined as the summation of far field vertical stress (σ_v) and drawdown pressure:

$$\sigma_{v,w} = \sigma_v + \Delta P_{dd} \qquad \textbf{(2)}$$

- Numerous TWC collapse tests were carried out on friable-consolidated sandstone have established that:
    - Collapse pressure of TWC (σ_{twc}) is 0-30% higher than initial failure pressure, $\sigma_{twc,i}$
    - On average:

$$\boldsymbol{\sigma_{twc,i} \approx 0.86 * \sigma_{twc}} \qquad \textbf{(1b)}$$

- The representativeness of this test for initial perforation failure has been investigated both experimentally and numerically.
- For example:
    - The effect of different stress regime
        - Isotropic (in lab)
        - Anisotropic (in-situ)
    - Limited ratio between outer and inner diameter of TWC sample have been investigated over a realistic range of conditions.
- The influence of this parameters lies within the uncertainty range of $\pm$15%.

TABLE 3: Description of Eq. 1 and Eq. 1b (Veeken et al., 1991)

Equation 1	**Equation 1b**
• Describe initial perforation failure, not subsequent enlargement and post failure stabilization • Based on intact rock testing	• Is compared to field observation of sand production events (transient, continuous and catastrophic) • Figure 8 shows that equation 1b is Conservative and can be used with confidence

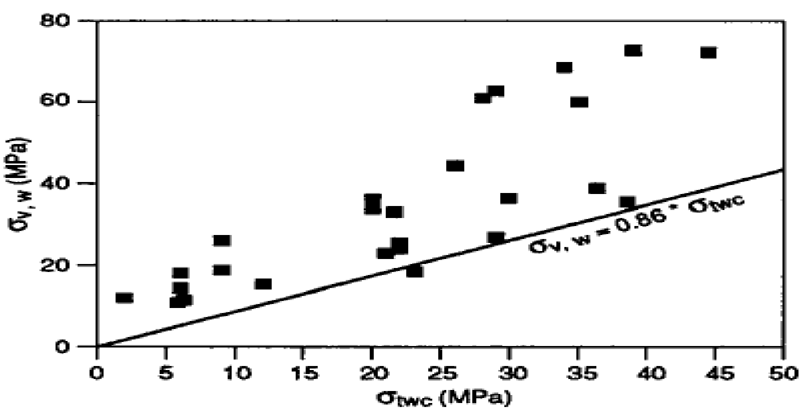


FIGURE 8: Near-wellbore vertical stress versus TWC collapse pressure (field data) (Kooijman et al., 1991)

2.2.2.3 Theoretical Modeling

Require mathematical formulation of the sand failure mechanisms which are (figure 9):

I. Compressive failure
II. Tensile failure
III. Erosion

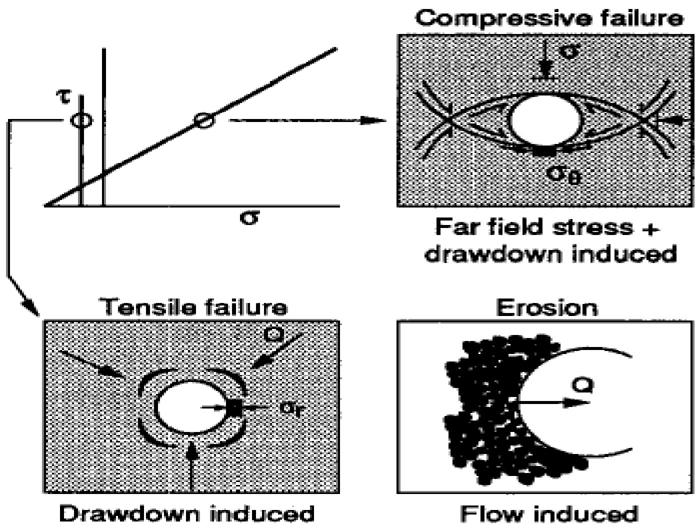


FIGURE 9: Sand Failure Mechanisms (Kooijman et al., 1991)

I. Compressive failure

- Refers to an excessive, near cavity wall, compressive tangential stress (σ_θ) which causes shear failure of the formation material.
- Triggered by both far field stresses (depletion) and drawdown pressure.
- Predominates in consolidated sandstone
- Has several models:

TABLE 4: Models of compressive failure

Elastic brittle failure model	**Elastic plastic material model**
• easy to implement • does not offer very realistic description of friable and loose materials	• more computational effort • enables more realistic description of the material behavior

- Modeling result is extremely sensitive to the choice of yield envelope and failure criterion
- **Yield envelope** may be chosen between:

TABLE 5: Choice of yield envelope (petrowiki)

Drucker Prager	**Mohr Coulomb**
• Pressure-dependent model for	• A mathematical model describing the

determining whether a material has failed or undergone plastic yielding. • The criterion was introduced to deal with the plastic deformation of soils. • It and its many variants have been applied to rock, concrete, polymers, foams, and other pressure-dependent materials.	response of brittle materials such as concrete, or rubble piles, to shear stress as well as normal stress. • Most of the classical engineering materials somehow follow this rule in at least a portion of their shear failure envelope. • Generally the theory applies to materials for which the compressive strength far exceeds the tensile strength.

- Choice of **failure criterion:**
  - Maximum plastic strain
  - Maximum plastic zone size
  - Maximum stress
- The use of different material models may lead to completely different results despite being based on same set of triaxial test data (Veeken et al., 1991).
- Material model needs to be validated against lab test data and field observation data. (not normally done)
- TWC empirical approach has been used as benchmark to compare various compressive failure models
- Most stability calculations are conservative with respect to the empirical tool and do not offer an advantage compared to the TWC approach
- Theoretical approach is useful in qualitative terms.
  - For developing optimum perforating policy (density, phasing, size)
  - Selective perforation of stronger zones
  - Formulation of guideline for maximum flow rate, maximum drawdown pressure, bean up and shut in

II. <u>Tensile failure</u>

- Refers to a tensile radial stress σ_r exceeding the tensile failure envelope
- Triggered exclusively by **drawdown pressure**
- Predominates **unconsolidated sands**
- Stability criterion expressed in terms of normalized drawdown pressure gradient (g_{pn}) at the cavity wall:

$$g_{pn} = \frac{\partial P}{\partial(\frac{r}{R})_{r=R}}$$

$$r = \text{radius of investigation}$$

$$R = \text{cavity radius}$$

- g_{pn} depends on the near wellbore permeability (figure 10) (Kooijman et al., 1991):
  - Higher g_{pn} is due to impairment
    - Perforating
    - Fluid invasion
    - Fines movement
  - Lower g_{pn} usually in case of simulation
    - Acidizing
    - Material dilation

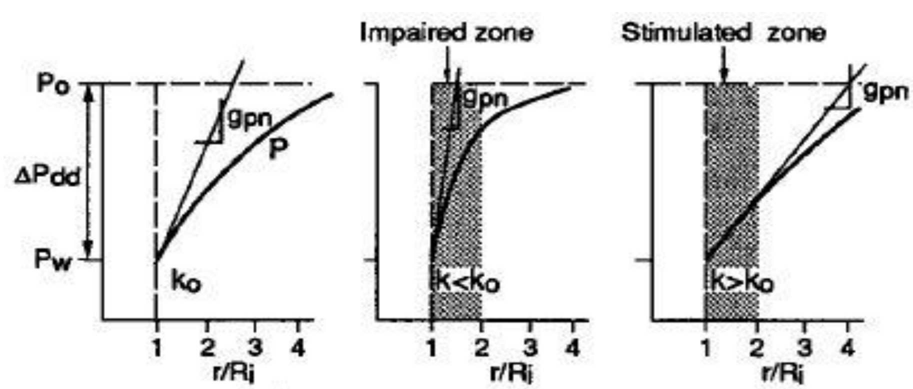


FIGURE 10: Dependence of normalized drawdown pressure gradient on near-cavity permeability (Kooijman et al., 1991)

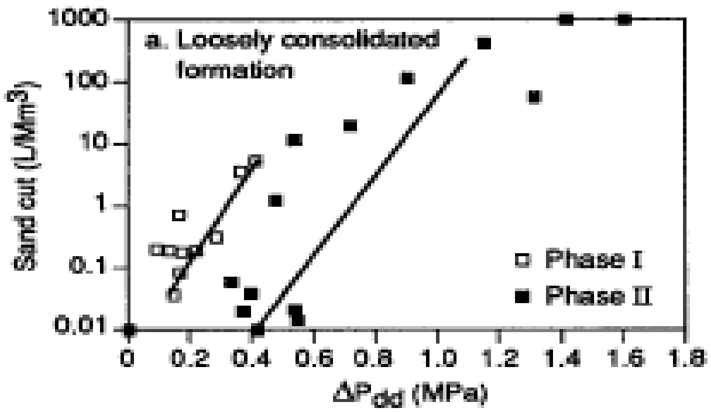


FIGURE 11: Sand concentration vs drawdown pressure for loosely consolidated formation (Kooijman et al., 1991)

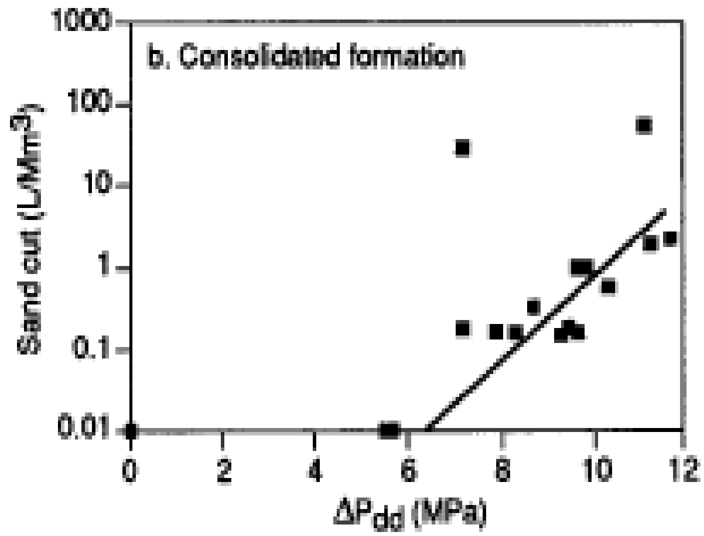


FIGURE 12**:** Sand concentration vs drawdown pressure for consolidated formation (Kooijman et al., 1991)

- Figure 11 and 12 above showed the sand concentration measured during sand production tests plotted against drawdown pressure for two cases.
- Sand concentration shows sharp increase with drawdown pressure (or flow rate) exceeds certain threshold
- This criterion is then compared to sand production field data in figure below where P_{dd} plotted against U_{cs}.

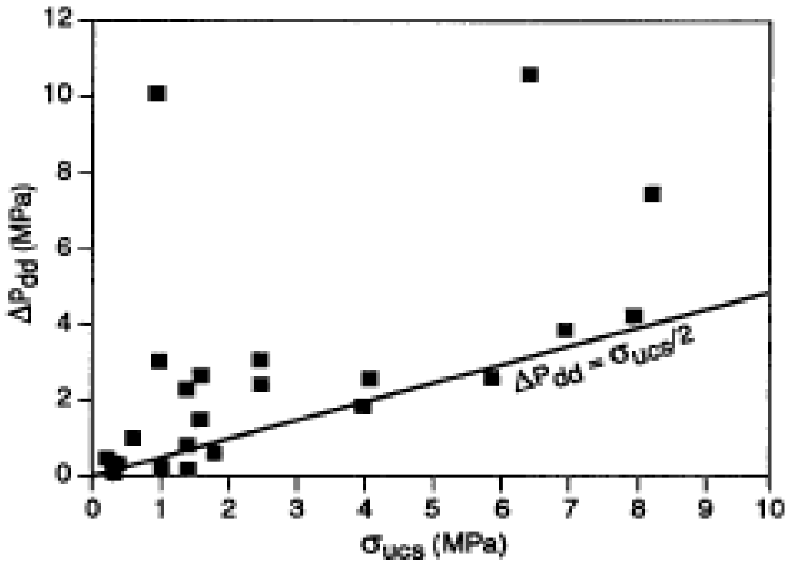


FIGURE 13: Drawdown pressure vs unconfined compressive strength (field data)

- Figure shows that $\mathbf{\Delta P_{dd} = 0.5*\sigma_{ucs}}$ provides conservative prediction of field sand production
- g_{pn} is high during transient flow stage due to bean up
  - The maximum tensile radial stress caused by bean up increment, $\Delta P_{dd,\,b}$:

    $$\sigma_r = -\Delta P_{dd,b}$$

    leading to the following tensile failure criterion during bean up:

    $$\Delta P_{dd,b} = \sigma_t$$

    where σ_t is the tensile strength (positive by convention).

  - Bean up criterion tends to be conservative as in practice, g_{pn} is reduced by fluid compressibility and wellbore storage effects.
  - Controlled bean up has been observed to reduce (transient) sand production in the field
- Different mechanism leading to tensile failure:
  - Shut in

- Plastically deformed material near cavity wall may develop tensile damage if stress unloading during shut in is excessive
- Subsequent bean up can cause more damage
- Amount of sand produced depend on pressure cycle magnitude ($P_{dd,\,c}$) and strength of material σ_{ucs} (Kooijman et al., 1991).

$$\Delta \mathrm{P}_{\mathrm{dd,c}} = \mathrm{L} * \sigma_{ucs}$$

Tensile failure is triggered by an excessive drawdown pressure gradient. This results in perforation or cavity enlargement, thus reducing g_{pn} to within acceptable limits. Compressive failure results from an excessive drawdown pressure ΔP_{dd} and may lead to catastrophic sand production. The position of the compressive failure envelope depends on the cavity geometry and the far field stresses.

III. <u>Erosion</u>

- Implies a gradual production of individual sand grains from cavity surface
- Special form of tensile failure
- Occurs when drag forces exerted at the sand face exceed its apparent cohesion
- Take place if drag forces exerted on a surface particle exceeds the (apparent) cohesion between surface particle
- Important parameter: **FLUID VELOCITY**
    - Confirmed by field experience

2.2.3 Sand Mitigation

2.2.3.1 Systems of Injecting Phenolic Resin Activator during Subsurface Fracture Simulation for Enhanced Oil Recovery

Oil recovery, particularly from economically marginal wells, is enhanced by injecting a fracturing material. The fracturing material is typically polymer-gelled water mixed with sand injected into the wellbore. The fracturing fluid is forced under pressure into the producing formation, hydraulically inducing fractures, and the fractures are propped open by the proppant, such as the sand. Other types of proppant besides sand include glass beads and certain ceramics. This process enhances production by permitting oil more distant from the hole to flow to the wellbore, from which it can flow or be pumped to the surface (Scott III, 1997).

Based on Scott, the oil industry often uses phenolic resin coating on proppants in such downhole reservoir fracture simulation procedures. Typically, after placement into the reservoir fracture, the resin coating on the proppant undergoes physicochemical change due to temperature and reaction with a chemical activator. The activator hastens the process first by softening the resin coat, which becomes sticky. Next, the resin-coated proppant material congeals into a hardened, permeable mass, thus inducing bonding of the packed proppant in the fracture. Such hardening is useful because (1) it helps reduce proppant migration from the fracture into the wellbore, which is undesired because it can cause granular erosion and sticking of the pump and other equipment during subsequent production, and (2) it reduces the likelihood of crushing within the fracture, which is undesired because it results in fine debris and increased fracture closure, thereby reducing fluid flow to the wellbore. The net result of the process is a polymer filter pack around the wellbore, which facilitates long-term pumping and enhanced fluid production rates (Scott III, 1997).

2.2.3.2 Polymer Coated Support and Its Use as Sand Pack in EOR

One of the problems encountered during CEOR is well degradation due to sand abrasion within the well caused by the co-production of the formation sand along with the oil. This is particularly troublesome in formations which consist of very fine, unconsolidated sand. One technique often used to protect the well from sand abrasion involves the introduction of a protective sand pack near the production zone by sequentially injecting graded sand and gravel to create a filtration medium. This will prevent the formation sand from entering the production well. The injected sand has a gradually increasing particle size, so that the finest sand is injected initially to be maintained at the bottom of the well, and the coarsest sand is injected last, to be maintained at the top of the sand pack (Whitehurst & Wu, 1990).

A polymer-coated, preferably highly-crosslinked polymer-coated, substantially non-friable support, such as sand, is prepared by depositing an olefin polymerization catalyst which is a chromium-containing or a chromium compound-containing catalyst (also known as a Phillips catalyst), a catalyst containing an oxide of a metal of Group VIB of the Periodic Chart of the Elements, such as tungsten oxide or molybdenum oxides, or a Ziegler catalyst, on the substantially non-friable support, and subsequently contacting the support with at least one multi-functional olefin monomer under polymerization conditions. As a result, a solid polymer surface is formed in situ on the non-friable support, and it effectively protects the support from the hostile environment of the underground oil formation. The thus formed polymer-coated non-friable support is used as a sand pack in enhanced oil recovery operations (Whitehurst & Wu, 1990).

2.2.3.3 Stand-alone Wire Wrapped Screen for a Polymer Injected Wells

A study regarding the design of horizontal polymer injectors was made by Marcel N. Bouts and Marleen M. Rijkeboer. The study was made for a redevelopment of a heavy oil field (160cp) with the application of polymer flooding as its EOR technique. The objective of this study is to minimize the number of wells and still achieving a significant injection rates of 500-750m3/d in the 30m thick reservoir by designing horizontal wells. Sand screen using a wire wrapped (WWS) screens with outflow control devices (OCD) are required for the completion criteria of the horizontal wells in order maximize injection conformance (Bouts, 2014).

Based on the authors, for achieving a high rate polymer injection, it is important to ensure that the viscosity of the solution is maintained in order for effective oil sweep to take place. The author also mentioned in their study that horizontal polymer injectors requiring both conformance and sand control should be designed such that high injection rates can be achieved without jeopardizing the viscosity of the polymer. Placement of horizontal wells in the middle of the oil column indicates that only a limited amount of polymer will be lost to the water zone and that high rates can be achieved and less wells are required (Bouts, 2014). For the studied development, the horizontal well requires sand control by means of wire wrapped screen (WWS) to avoid formation failure when injection stopped. This statement proved that WWS can be applied to wells that are undergoing EOR by polymer flooding.

In this case study, stand-alone wire wrapped screen with a slot size of 200-225 micron were chosen as the means for sand control. When using these screens about 7% of the horizontal well is open to flow. The experiment was conducted using various injection rates and completion efficiencies (i.e. part of the screen can be plugged) and the shear rate was calculated using the equation of pipe flow:

$$\gamma = \frac{8v}{d}\gamma$$

γ = shear rate (1/sec)

v = velocity (m/s)

d = diameter of screen slot in microns

The results of the calculations are shown in Table 3. These shear rates are considered to be low and thus no mechanical degradation is required (Amaral et al., 2008).

TABLE 6: Calculated shear rates (1/sec) through various wire wrapped screen configurations (Bouts & Rijkeboer, 2014)

	COMPLETION EFFICIENCY (FRACTION)		
Injection rate (m^3/d)	**0.5**	**0.75**	**1**
350	18	12	9
500	25	17	13
650	33	22	16
750	38	25	18

However, another laboratory tests were conducted to measure whether any decrease in viscosity would happen due to mechanical shear degradation of the polymer through the screen. Actual screen samples were used through which polymer was flowed and the viscosity was then measured before and after the screen. The flow rates of 0-5 1/h were applied in the lab tests and covered the range of expected shear rates of 0-60 1/s. Figure 5 shows the results for two types of synthetic polymer. Polymer 1 is a ter-polymer with a molecular weight of 11-14 x 106 and polymer 2 is a co-polymer with a molecular weight of 6-9 x 106. The tests were conducted at two different polymer concentrations in case an optimization would be required. It can be concluded that no significant polymer degradation has occurred at the tested rates.

Based on the experiments for the studied case, a conclusion has been made and it is concluded that the risk of mechanical shear degradation of polymer through sand screen in horizontal wells is limited, provided that the screens are sufficiently cleaned after completion resulting in high completion efficiency factor (Bouts, 2014). This proved that wire wrapped screen is effective and can be applied for wells that are applying polymer flooding as their enhanced oil recovery method.

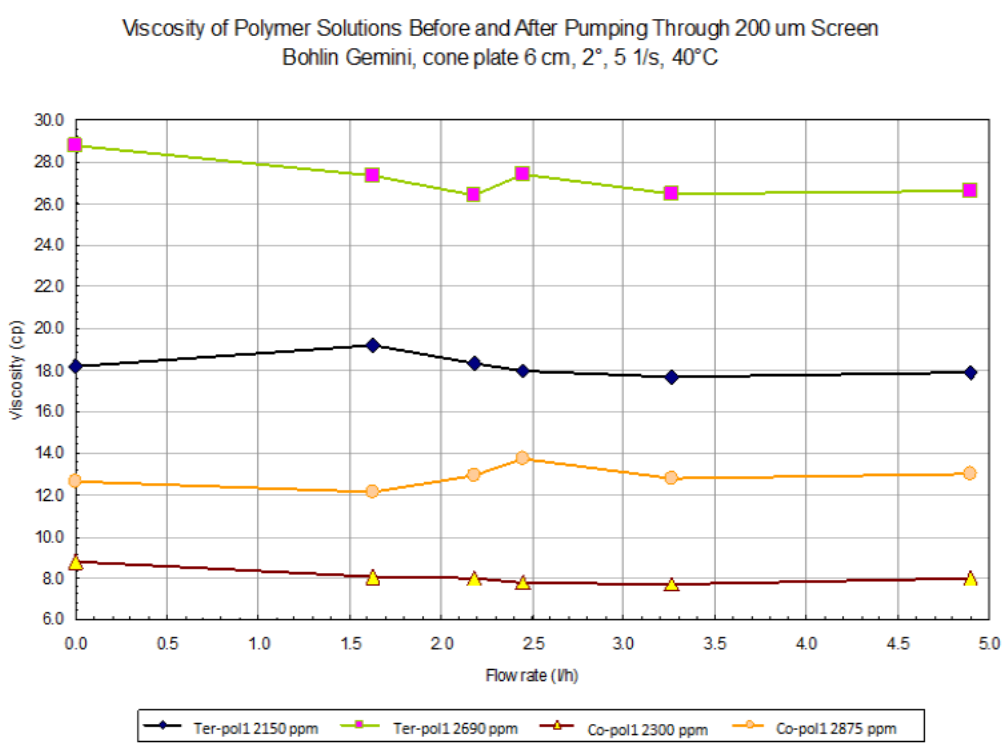


FIGURE 14: Shear degradation tests of two types of polymer through the sand screen (Bouts & Rijkeboer, 2014)

CHAPTER 3

METHODOLOGY

3.1 Research Based Project

This project is a research based project regarding sand production prediction and mitigation during Chemical EOR. The objective of doing this project is to determine the factors of sand production during Chemical Enhanced Oil Recovery operation, to review the method for predicting sand production in CEOR wells applications and to review the latest sand control technologies for Chemical EOR wells application. The methodology of doing this project can be divided into three parts.

3.1.1 Extensive Literature Review

The author will conduct an extensive literature review on:

3.1.1.1 Enhanced Oil Recovery

- What is EOR?
- Where do people apply EOR?
- How it is applied? The process?
- What are the processes involved?
- When it needs to be applied?
- Why does it need to be applied?

The scope will then be narrowed to:

- Types of EOR
- Current technology (focus on Chemical EOR)
- Concerning issue (sand production during CEOR operation)

3.1.1.2 Sand Production

- What is sand production?
- Where does sand production occur?
- How does it occur?
- When does sand production take place?
- Why does it occur?

Scope will be narrowed down to:

- Factors causing sand production during CEOR operation
- The effects of sand production.
- Available method to predict sand production in CEOR wells applications.
- Latest sand control technology available for CEOR wells applications.

3.1.2 Ishikawa Diagram

The author will construct an Ishikawa diagram which is also known as a root-cause analysis diagram based on the factors that causing sand production to occur during chemical EOR operation. This diagram provides an analysis on sand production issue in CEOR wells.

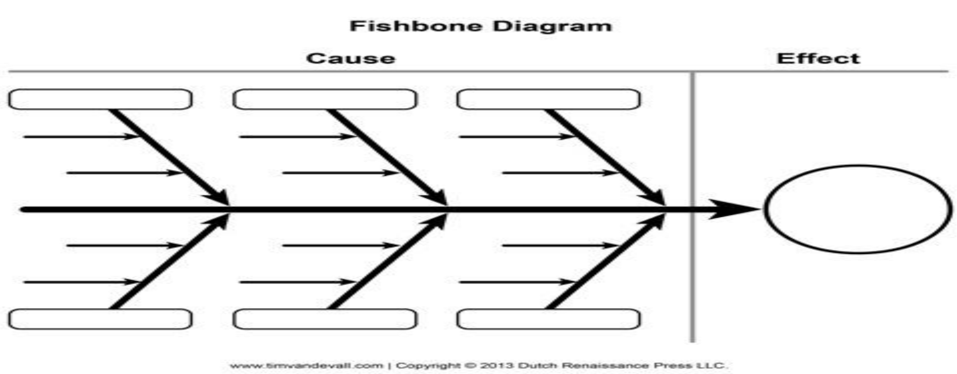


FIGURE 15: Example of Ishikawa Diagram

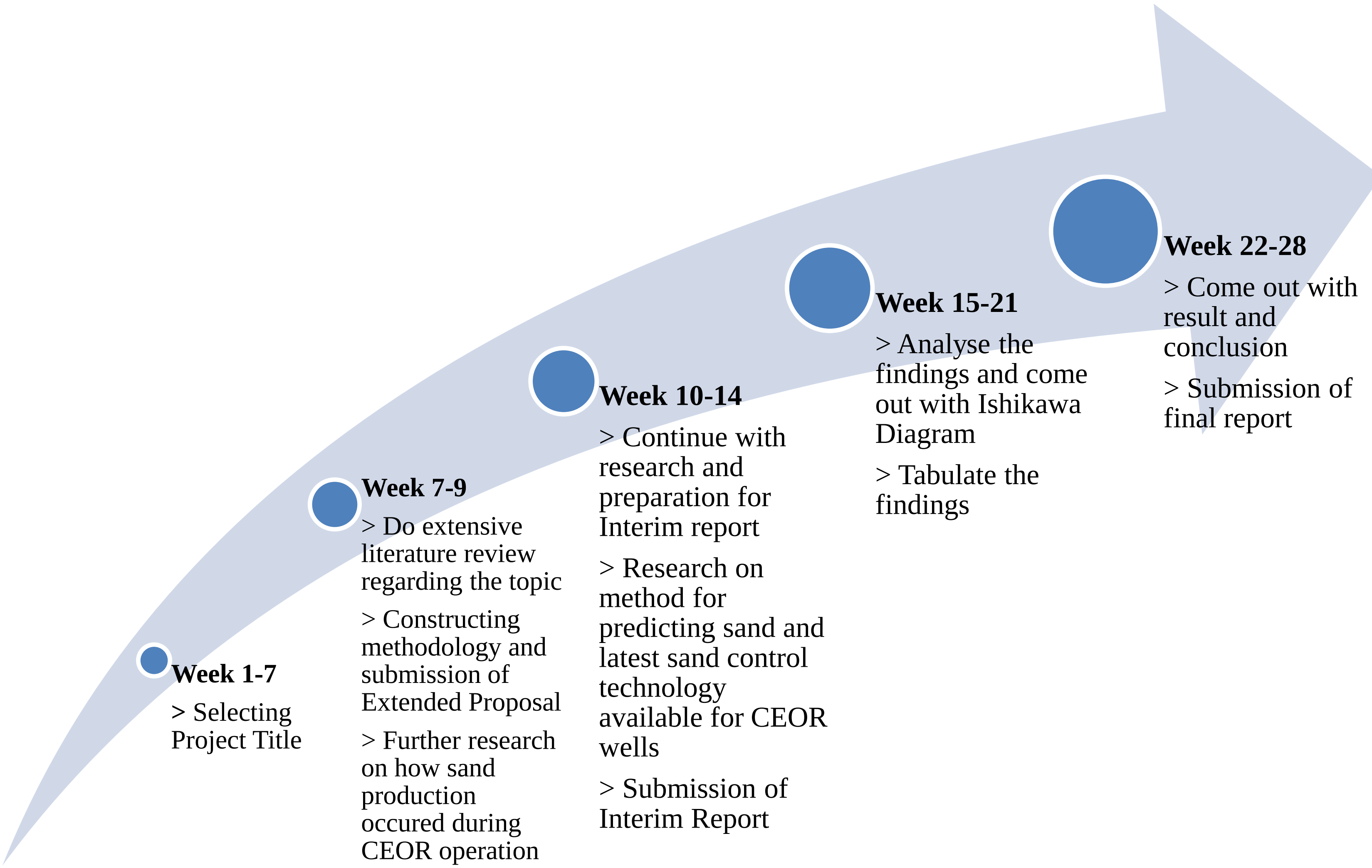
3.1.3 Table Analysis

A table will be presented based on the reviewed sand production prediction method and sand control technologies.

3.1.4 Conclusion and Summary

A conclusion will be made based on the analysis of which method can be applied for predicting sand production during CEOR operation and what are the sand control technologies available for mitigating sand production in CEOR wells applications.

3.2 Key Milestone



3.3 Gantt Chart

TABLE 7: FYP 1 Gantt Chart

No	Detail	Week													
		1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	Selection of Project Title														
2	Preliminary Research Work and Proposal Preparation														
3	Submission of Extended Proposal														
4	Proposal Defence Presentation														
5	Continuation of all project work														
6	Submission of Interim Draft Report														
7	Submission of Interim Report														

TABLE 8: FYP 1 Gantt Chart

No	Detail	Week													
		1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	Project Work Continues														
2	Submission of Progress Report														
3	Project Work Continues														
4	Pre-SEDEX														
5	Submission of Draft Final Report														
6	Submission of Dissertation (soft bound)														
7	Submission of Technical Paper														
8	Viva														

CHAPTER 4

RESULTS AND DISCUSSION

4.1 Results

4.1.1 Ishikawa diagram on factors of sand production during Chemical EOR

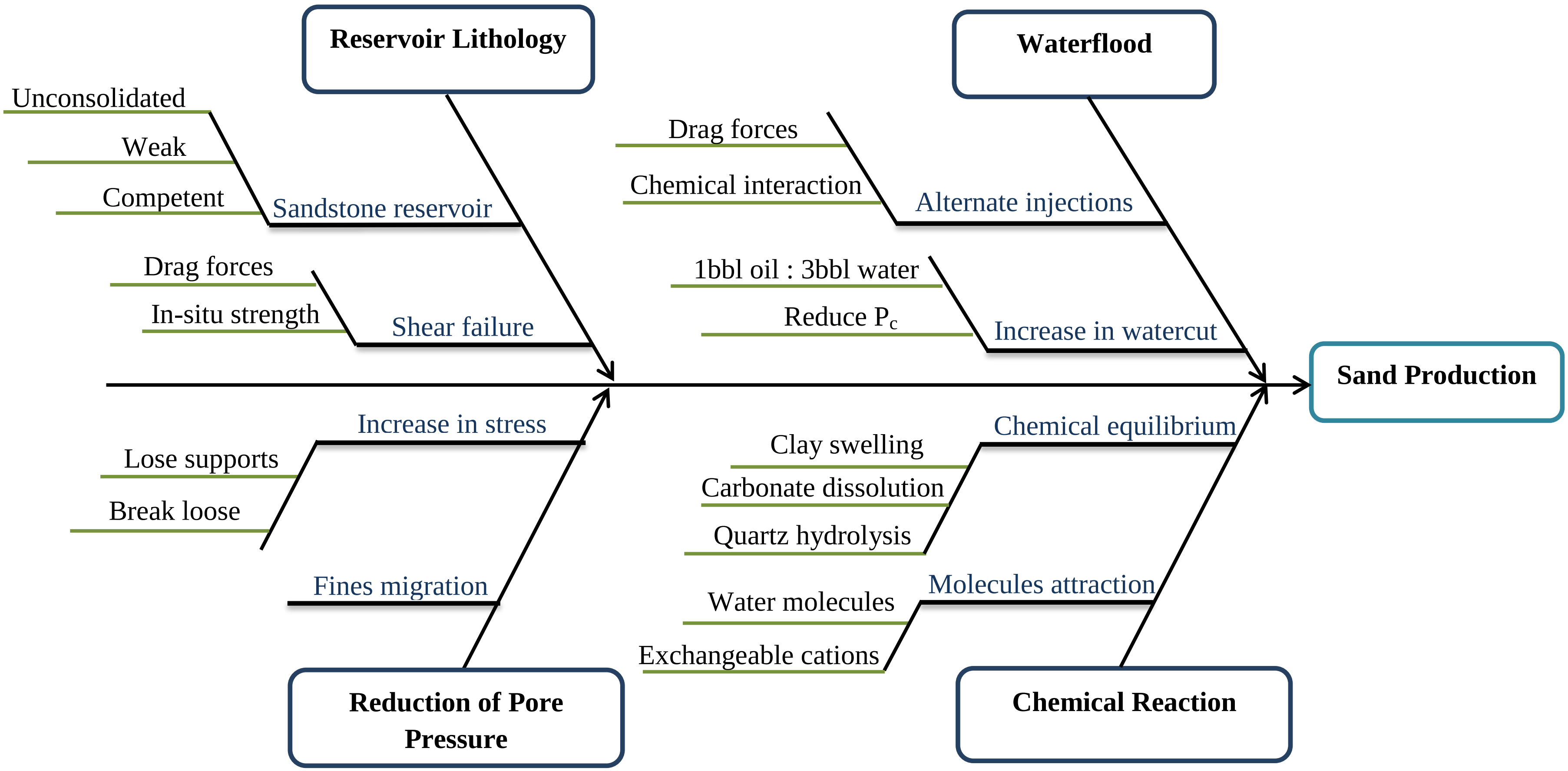


FIGURE 16: Ishikawa diagram on factors causing sand production

4.1.1.1 Reservoir Lithology

Based on literature review made in the previous section, Figure 4 shows that most EOR operations were applied in sandstone reservoir. Sand production occur when insitu stress exceed formation in-situ strength. The three classes of formations which are unconsolidated, competent and weak formation usually produces sand along with the reservoir fluid. This is due to the shear failure which occurs at the surface of the rock. As chemical EOR are usually applied in sandstone reservoirs, sand production are prone to occur during the enhanced oil recovery operations.

To support this statement, according to Sheng (2010), in his book entitled Modern Chemical Enhanced Oil Recovery: Theory and Practice, he mentioned that almost all chemical EOR applications have been in sandstone reservoir, except for a few simulations projects and a few that have not been published have been in carbonate reservoir. Some factors that cause fewer applications in carbonate reservoir are due to its high adsorption of the anionic surfactants and also due to the presence of anhydrite in the formation which will lead to precipitation and high alkaline consumption. Moreover, he also mentioned that clay formation will cause high surfactant and polymer adsorption and high alkaline consumption. Thus, clay contents should be low for a chemical EOR application to be effective (Sheng, 2010).

Generally, sandstone reservoirs show the most promising result to implement EOR projects as most of the technologies have been tested at pilot and commercial scale in this type of lithology. One good example of a field that has already applied chemical EOR technology in sandstone formation and was evaluated to be successful was Carmopólis oil field in Brazil (Alvarado & Manrique, 2010). Carmopólis is an onshore heavy oil (22 °API) reservoir that is operated by Petrobras. This field applied polymer flooding as their CEOR method in 1969 up until 1972. Application of chemical EOR in sandstone formation will surely risk the wells to sand production as sandstone reservoir is prone to producing fines. EOR is applied at a later stage of a field's life, pore pressure is depleted by age of the reservoir and that will cause loss in weight supports of the rock (Carlson, Gurley, King, Price-Smith, & Waters, 1992) and thus creating a high shear stress. This will then lead to induced shear failure on the rock's surface and produce a mobilized sand debris (M. N. Al-Awad, 2001).

4.1.1.2 Waterflood

All the three methods of Chemical EOR applications are applied with alternate injection of water. Based on Shah surfactant slug is driven through the reservoir by a subsequent slug of water (Shah, 1977). One of the causes of sanding includes water influx, which commonly cause sand production by reducing capillary pressure between sand grain. After water breakthrough, sand particles are dislodged by flow friction (Carlson et al., 1992). This will increase the water production in the reservoir thus inducing sand production to occur.

The same thing is applied during the injection of polymer. Polymer solution is injected in conjunction with water flood. Water begins to produce as water cut increases and this triggers sand production to occur. Water breakthrough is a common technical problem encountered in oil field. Severe channeling will results in low water displacement efficiency and sometimes can even make the injection uneconomical (Wang, Liu, & Gu, 2003). It is well known in the rock-mechanics community that increase in water saturation has a strength reduction effect for all types of rock (Dyke & Dobereiner, 1991). In general, the weaker the rock, the more sensitive it is to changes in moisture content. Wu and Tan (2001) presented an experimental study on the effect of water/oil saturation in sandstone strength for a number of downhole and outcrop weak sandstones. It was found that, increase in water saturation will reduce the capillary strength bonding and alter the relative permeability which will then resulting in an increase in drag force and this mobilize the sand grains from the failed rock strength (Bailin Wu et al., 2006).

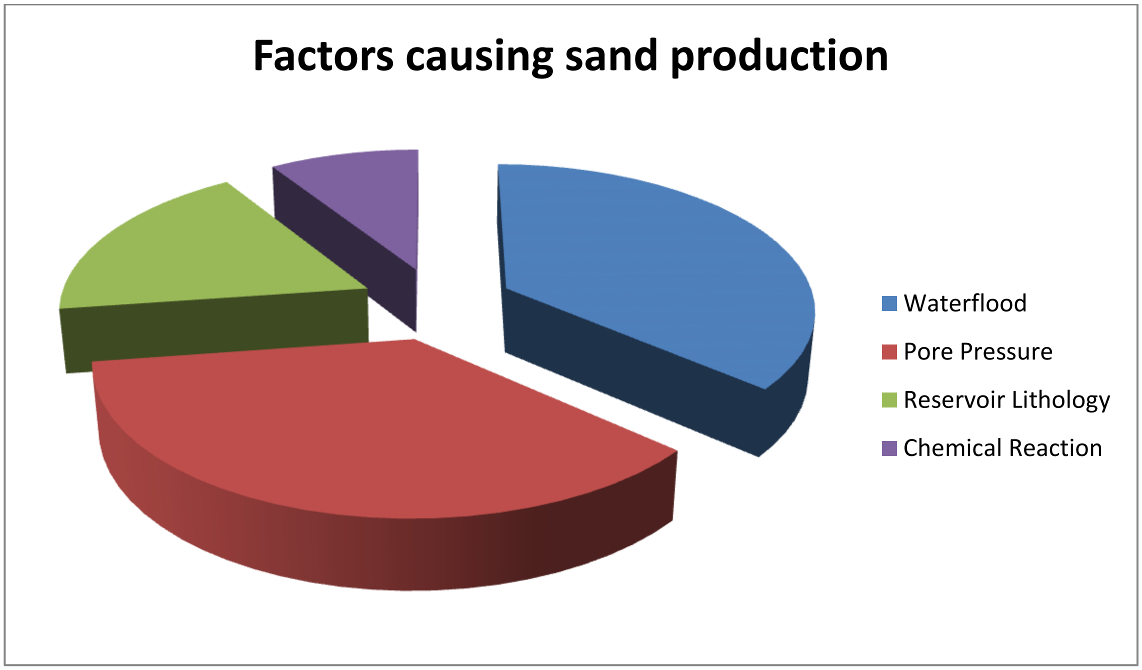
4.1.1.3 Reduction in Pore Pressure

Reservoir pressure decreases as the age of the reservoir increases. The reservoir pressure supports some of the weight of the overlying rock and these supports decreases as reservoir is depleted. Sand production is initiated when the formation stress exceed the strength of the formation. The formation strength is derived mainly from natural material that cements the sand grains. However, the sand grains are also held together by cohesive forces resulting from immovable formation water. The stress on the formation sand grains is caused by many factors notably; tectonic actions, overburden pressures, pore-pressures, stress changes from drilling, and drag forces on producing fluids. In some cases, the onset of sand production occurs late in the life of a field when pressure have declined to the extent that the overburden is being supported mainly by the vertical component of inter grain stress rather than by the pore pressure. This may cause shearing of the cementing material allowing the sand grains to move and hence be produced into the wellbore or, below a certain pore pressure, the point stress between the sand grains exceeds their fracture strength and the grains collapses causing instability and onset of sand production (Mohamed et al., 2012). This will create fines which then will produce together with the reservoir fluids. As enhanced oil recovery is applied after 30% of total reservoir production, the pore pressure of the reservoir is already reduced and this low pressure creates an increasing amount of stress on the formation sand and causing it to break loose from the matrix (Zhang et al., 1998)

4.1.1.4 Chemical Reaction

The chemical reactions will take place in the reservoir once it is injected. Some of the possible chemical reactions are clay swelling, carbonate dissolution and quartz hydrolysis. All of these interactions will attract layers of water molecules as water molecules are dipolar. This will increase water production which can initiate sand production. Grain to grain cohesiveness that initially provided by surface tension of connate water is reduced as it adheres to produced water. As water cut increases, relative permeability to oil decreases and it will results in a larger pressure differential for a given rate. The reduction in cohesiveness and increase in shear force increases the likelihood of sand production.

4.1.1.5 Weightage of the Effects of the Factors Causing Sand Production



From this pie chart, the author can conclude that waterflood affect the sand production the most. Other than that, this factor can be controlled by reducing the amount of water injected.

4.1.2 Method for predicting sand production

TABLE 9: Sand production prediction method

Method	Description
Field observation technique	Establish correlation between sand production well data and field operational parameters. I. One parameter II. Two parameters III. Multi parameters
Laboratory sand production experiment	Use a thick walled cylinder (TWC) approach • Measure initial failure of a perforation by assuming that it can be related to the initial failure of a hollow cylinder sample (observe visual damage).

	• Carry out numerous TWC collapse tests and established that collapse pressure of the TWC is 0-30% of initial failure pressure. $$\boldsymbol{\sigma_{twc,i} \approx 0.86 * \sigma_{twc}}$$ ▪ Sand production occurs at the collapse pressure.
Theoretical modeling	I. Compressive failure • Refers to an excessive near cavity wall, (compressive) tangential stress which causes shear failure of the formation. This condition can be triggered by depletion pressure (far field stresses) and drawdown pressure. • Compare with laboratory and field data. II. Tensile failure • Refers to a tensile radial stress exceeding the tensile failure envelope and triggered solely by drawdown pressure. • Another mechanism leading to tensile failure is shut in. Stress unloading during shut in will cause plastically deformed material and results in produced sand. III. Erosion • Occurs when drag forces exerted in a particle at the sand face exceed its apparent cohesion. • Implies a gradual production of individual sand grains from the cavity surface. • Important parameter: fluid velocity • Fluid velocity at which sand is produced is measured.

4.1.2.1 Correlating Sand Production Field Data

Linear regression techniques using data from different wells may obscure the actual influence of field and operational parameters. In Fig. 17 sand concentration is plotted against drawdown pressure; the drawdown pressure does not notably influence the sand cut and would not appear as significant in a correlation exercise. In Fig. 18 changes in sand cut are plotted against changes in drawdown pressure for individual wells in the same field. A definite influence of drawdown pressure can now be seen. The more similar the characteristics of the various wells, the greater the expected success of correlation techniques. The on/off influence of water cut would have dominated the multi-variable linear regression, thus making it less sensitive to the other factors. Records of sand production spanning a longer period are most valuable for assessing the influence of depletion and water production (Alcocer & Kollba, 1989). Variations associated with differences in formation strength, inflow performance, perforation policy etc. are thus excluded. In Fig. 19, sand cut, water cut and gross production rate are plotted against time the onset of sand production with water breakthrough is clearly established. In this case the flow rate was beaned back to restrict the sand production rate.

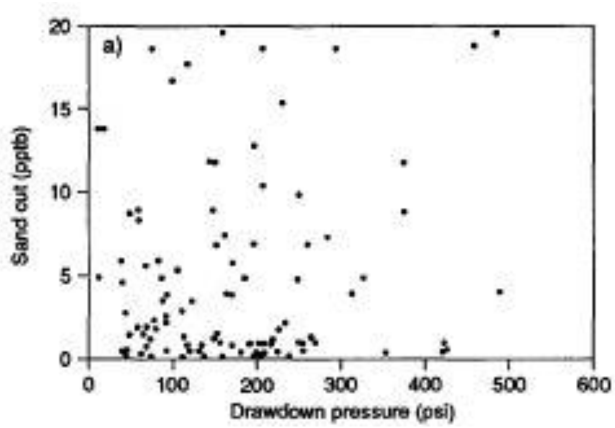


FIGURE 17: Effect of drawdown pressure on sand production (field data) (Veeken et al., 1991)

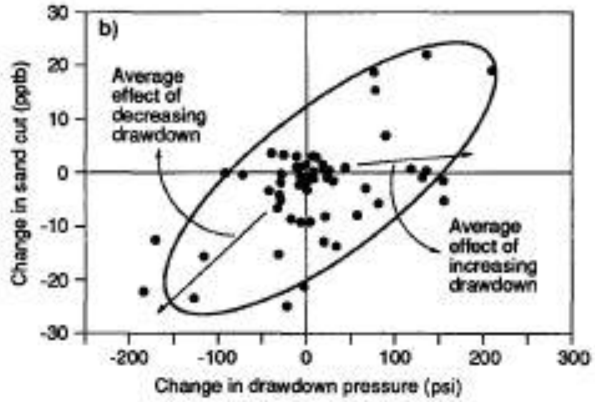


FIGURE 18 Effect of drawdown pressure on sand production (field data) (Veeken et al., 1991)

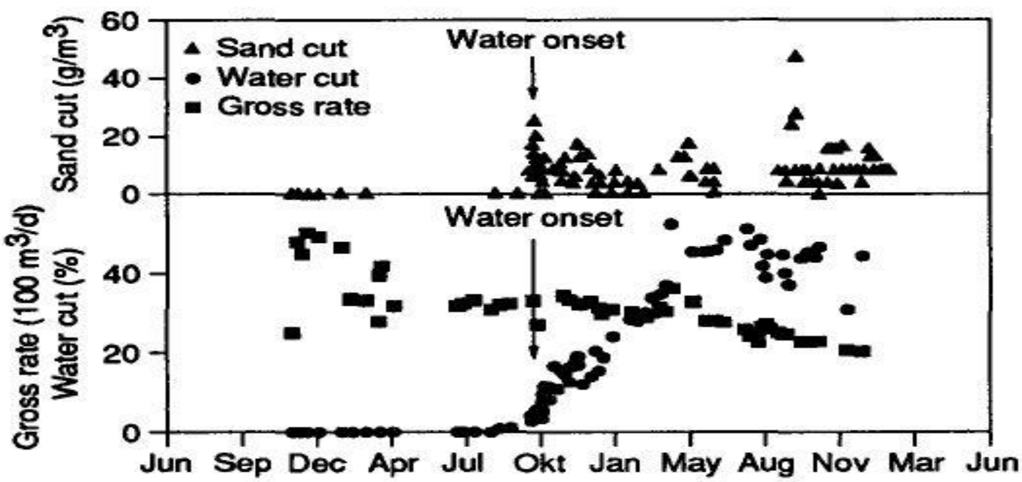


FIGURE 19: Record of gross rate, water cut and sand concentration (Veeken et al., 1991)

4.1.2.2 Laboratory Sand Production Experiment

The TWC approach assesses initial failure. The presence of the outer boundary causes the sample to collapse and prevents the study of e.g. hole enlargement (Alcocer & Kollba, 1989). The size of reservoir core samples is generally limited to 4 in. diameter. This limits laboratory sand production testing to e.g. single perforations or cavities whose enlargement is limited. In case of unconsolidated and loosely consolidated materials the TWC collapse pressure is less meaningful as sample failure is then governed by the pressure necessary to extend the plastic zone to the outside of the sample (Veeken et al., 1991). Thus, the influence of the boundary stress on sand production from a weakly consolidated core sample may be exaggerated. In the absence of detailed field information concerning the effect of sand production on the downhole geometry, large scale testing is necessary to facilitate a realistic simulation of in-situ sand production (Van den Hoek et al., 1992). A laboratory test of a completion including casing, cement and perforations situated in a large sample would allow the investigation of perforation enlargement and coalescence, and of the influence of perforation policy and borehole orientation on sand production. Such equipment is available for industry use. By comparing large scale and small scale sand production tests, correction factors necessary to translate the test results on small scale core samples.

4.1.2.3 Theoretical modeling of sand production

Morita et al. (1989) demonstrated that the influence of various field and operational parameters on transient and catastrophic sand production can be understood qualitatively using current rock mechanical modeling techniques (Morita, Whitfill, Massie, & Knudsen, 1989). To improve the rock mechanical sand prediction models, validation with respect to lab or field sand production data is essential. Advanced numerical and material modeling will be required to further study the sand production mechanisms e.g. to realistically simulate cavity enlargement, the influence of material dilation, and the interaction between compressive and tensile failure (Kooijman et al., 1991).

4.1.3 Sand Control Technologies Available For Mitigation Of Sand Production For CEOR Wells.

4.1.3.1 Chemical Methods

TABLE 10: Sand Control Technology for CEOR Wells Application

Injecting Phenolic Resin Activator	• This method uses phenolic resin to coat proppants (usually sand) in downhole reservoir fracture simulation.

	• The resin coated proppant materials congeals into a hardened, permeable mass, thus inducing bonding of the packed proppant in the fracture. • This well help in reducing proppant migration into the wellbore and reduce its tendency to crush within the fracture.
Polymer Coated Support and its use as Sandpack in EOR	• Protective sandpack is used. • Graded sand and gravel is injected near the production zone to create a filtration medium. • Preventing sand from entering production wells • Sand injected is of different sizes; started with finest sand and proceeds with increasing particle sizes. • A preferably highly crosslinked polymer coated, substantialy non-friable support is used as the sandpack to prevent sand from entering the production zone. • This sandpack is designed such that it us resistant in deterioration due to high temperature, pressure and alkaline condition existing in the subterranean formations.

4.1.3.1 Mechanical Method

TABLE 11: Sand Control Technology for CEOR Wells Application

Use of Stand Alone Wire Wrapped Screen	• A wire wrapped screen is used in a case study with the objective of minimizing the number of wells and still achieving a significant injection rates of 500-750m3/d in the 30m thick reservoir by designing horizontal wells.

	• Stand alone wire wrapped screen with a slot size of 200-225 micron was used as a sand control method in this field case study. • The stand alone screen was used together with gravel pack completion to control the sand production in the wells during polymer injection. • A number of experiments were conducted to test the efficiency of the completion and to test whether a high rate of polymer injection contribute to the mechanical degradation of the completion. Tests were conducted using different types of polymer with different shear rate and flow rates and the results showed that no significant polymer degradation occurred at tested rates. • From the experiments, a conclusion is drawn that sand screen is effective to be used during polymer flooding application provided that it is suffiiciently cleaned after completion.

CHAPTER 5

CONCLUSION AND RECOMMENDATIONS

Sand production brings negative effects to the production of hydrocarbon in a reservoir. The accumulation of sand during recovery process will defeat the main objective of EOR which is to increase the production. As there is no guideline on sand production prediction and mitigation during CEOR operation, the objective of doing this project are to find the factors that cause sand production during the operation, to review sand production prediction methods and also to review latest sand control technologies available for mitigation of sand production in CEOR wells.

An extensive literature review was made continuously since the early stage of this project regarding all the subjects stated in the objective. The factors that cause sand production were analyzed and relate with CEOR operation and it can be concluded that sand production also occurs in CEOR wells. Sand production prediction methods were reviewed and discussed in literature review and also results. Other than that, sand control technologies that are available for mitigation of sand in CEOR wells were also reviewed. However, only three technologies that was available to be found from research papers online. The author believed that the reason of this limitation is because not many operators have applied sand control during chemical EOR operations especially for fields that are located in Malaysia.

For the recommendation, the author would like to recommend operator and service companies to provide a specific guideline and disclose the information to public for future references. Other than that, the author would also like to strongly suggest sand mitigation to be applied during chemical recovery since the production of sand will only bring negative effects to the oil production.

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