PRACTICAL APPROACH TO EFFECTIVE SAND PREDICTION, CONTROL AND MANAGEMENT

A

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PRACTICAL APPROACH TO EFFECTIVE SAND PREDICTION, CONTROL AND MANAGEMENT

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ABSTRACT

The production of formation sand is a problem associated with most oil deposits in the world. Major Sand production effects affect safety, well or field economics and continuous production. This has prompted the continued search for solutions to mitigate sand production in the oil and gas industry over time. The methodology often employed is through exclusive sand control or passive sand management. The ability to predict when a formation will fail and produce sand forms the basis as to what type of sand management strategy to use (whether downhole sand control system will be required or a sand management approach). As a result sand prediction forms the basis for major reservoir development plan. Variety of models available, their applicability and accuracy can be confusing and not representative of the production experience. Also, the concept of sand prediction, control and management is often treated separately. This study views sand prediction, control and management as an interdependent concept (Holistic). Review of State of the art sand prediction, control and management is carried out to proffer better understanding of the concept of sand production management. The mechanism of sand production is discussed with highlight of major parameters influencing sand production. It is identified that sand prediction forms the basis for reservoir development plan, therefore effective methodology for sand prediction, control and management is developed. Stepwise approach to carry out this concept is presented with flow charts and guidelines. In conclusion the study states the importance of data accuracy in sand prediction, the use of risk quantification. Quantifying uncertainties inherent in most predictions will help deploying the right type of sand management strategy in a formation.

ACKNOWLEDGEMENT

Everything that has a beginning must equally have an end. I appreciate God for the gift of life in good health and abundant grace throughout my stay in this great citadel. Thank You FATHER. Its indeed a privilege and honour to pass through this school. I acknowledge the effort of every lecturer that has impacted knowledge into me, without your contributions I would not be who I am today.

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DEDICATION

I dedicate this thesis work to Almighty God for giving me the grace to complete it and to my parents for their love and support.

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CHAPTER ONE

PROBLEM FORMULATION

1.1 Introduction

The production of formation sand is a major problem encountered during the production of oil and gas. Over 70 % of the world's oil and gas reserves sit in sand formations where sand production is likely to become an issue during the life of the well (Osisanya, 2010). Sand production is typical of tertiary formations (with permeability of 0.5 to 8 Darcy) and older formations as they enter their mature stages of production due to poor completion and impact of depletion. Areas where severe sand production problems occur include Nigeria, Trinidad, Indonesia, Egypt, Venezuela, Malaysia, Canada tar sands and Gulf of Mexico. The reservoirs in these formations lie between 3,500 ft and 10,000 ft (subsea). Generally, the effects of sand production ranges from economics and safety hazards to well productivity and therefore has been an issue of interest to tackle in the petroleum industry. Some of these effects include erosion of downhole and surface equipment, pipeline blockage and leakage, formation collapse, damage to casing/production liner due to formation subsidence, and increased downtime. These devastating effects lead to more frequent well intervention and workovers generating additional needs for sand disposal particularly in offshore and swamp locations. The effects of sand production are nearly always detrimental to the short and or long term productivity of the well (William and Joe, 2003). In order to mitigate problems related to sand production new strategies are being continuously investigated, from prediction to control and management. The ability to predict when a reservoir will fail and produce sand is fundamental to deciding whether to use downhole sand control or what type of sand control to use (Bellarby, 2009).

Sand production occurs normally as a result of drilling and reservoir management activities. Sand grains are disengaged from the rock matrix structure under physical (earth stress) and chemical action. The mechanism of sand production in terms of sand, volumes and sand producing patterns in the reservoir is needed to optimally develop a field. Mechanisms causing sand production are related to the formation strength, flow stability, viscous drag forces and pressure drop into the wellbore (Osisanya, 2010). The critical factors leading to accurate prediction of sand production potential and sand production are: formation strength, in-situ stress, and production rate. Other factors are reservoir depth, natural permeability, formation cementation, compressibility, surface exposed to flow, produced fluid types and phases, formation characteristics, pressure drawdown and reservoir pressure. Predicting sand production involves developing empirical and analytical techniques. Empirical techniques relate sand production to some single parameter or group of parameters such as porosity, flow or drawdown analytical techniques relates to rock stresses. Numerical analytical techniques are also sometimes used. They are models developed from finite element analysis. The techniques above use production data, well logs, laboratory testing, acoustic, intrusive sand monitoring devices, and analogy (Osisanya, 2010). At present, predicting whether a formation will or will not produce sand is not an exact science and needs more improvement.

Currently, there are two main classes of techniques available for sand management: sand prevention by passive method and sand control using mechanical exclusion (gravel packing); or screenless completion (sand stabilization by chemical consolidation or sandlock) (Osisanya, 2010). Chemically consolidating the formation around the wellbore with a plastic material is best applied to production intervals which are relatively free of clays and fines, have uniform permeability, are thin and have no prior history of sand production (Schechter, 1992). Preventing the production of sand using passive methods includes techniques to minimize or eradicate sand production to manageable levels. This includes perforation techniques and maximum sand-free drawdown rate. Limiting production rates to avoid sand production in some cases is the most cost-effective method of sand control. In most cases however, low production rates are uneconomical stressing the need for sand control. Sand control tools do not only serve the purpose of preventing the sand grain from entering the wellbore, but also to protect the rock matrix structure, preventing formation damage. At present, set standards to determine which type of control means to administer to a well does not exist. A lot of factors are considered to determine the method of control to use. Some of which are: the type of sand (fine or coarse), length of pay interval, variations in permeability, hole deviation, availability of rigs, and formation sand uniformity.

1.2 Literature Review

The subject, sand prediction control and management, is broad with several books and publications written with the intent of understanding the critical factors leading to sand production, developing models of predicting sand production potential and various techniques of sand control. These publications discuss sand failure mechanism, components of sand production (rock strength, in-situ stresses and production rate) and techniques to efficiently measure some of these components. The onset of sanding has been investigated for more than 40 years (Han et al, 2009). The approaches of these publications are experimental, analytical (models) and numerical (though not common due to unavailable data, timing and resources) including field experience. The goal of most of the publications is to determine whether sand control decisions should be taken during field development. Studies have shown that it is important for the rock strength to be correctly estimated in predicting the sand potential of a formation. The trend is the determination of formation strength and field stresses and the application of them to a failure model.

Zhang et al., (2000) established that the mechanical strength of a formation is crucial information required for predicting sand production and recommending sand control completion. The model presents a method of measuring rock strength such that the restrictions from core testing (as cores are not always available) can be avoided. They conducted tri-axial and hydrostatic test; to construct the failure envelope. The results of the studies showed a single normalized failure envelope used to characterize sandstone formations making it possible to construct the failure envelope for a sandstone formation from the knowledge of critical pressure. A correlation exists between the critical pressure and compressional wave velocity (at equivalent depths of burial).

Weingarten and Perkins, (1995) conducted a research on prediction of sand production in gas wells. The method proposed was applied to 13 fields in the US Gulf coast area and has since been used extensively worldwide by the defunct Arco. The rock strength was determined by core testing and log correlations and the results compared. The prediction method differs from commonly used log-based sand prediction model. They modeled pressure gradient in the reservoir, not assuming pressure drop occurs at the perforation face and allows higher drawdowns than those permitted using shear failure criteria. Their model however predicts the onset of sand production and is not designed to apply to situations where some level of sand production is allowable. Water influx was not taken into consideration.

Osisanya, (2010) attributed sand production to recent clastic sediments and gave practical guidelines for predicting sand production. The most critical factors to sand production were stated as formation strength, changing in-situ stresses and fluid production rate. Sand prediction methods described include production test, well log analysis, laboratory mechanical rock testing, acoustic, intrusive sand monitoring devices and analogy. To support these methods examples and case studies from the Africa, Europe and USA were given. The paper highlighted data required to predict sand production as production test data, formation intrinsic strength, rock dynamics elastic constants, and log data.

1.3 Problem Description

A continued search for improved means of mitigating sand production exists in the petroleum industry as most of the world's reservoir sit in sand prone formation. The potential to produce sand in a formation increases as the reservoir is been depleted and water influx sets in. This is the likely occurrence in production and injector wells because the effective overburden pressure of the formation increases. Also as the production rate from the reservoir increases the fluid pressure gradient near the wellbore tends to draw sand into the wellbore. Increasing reservoir production rate raises the probability of reaching the reservoir boundaries. The effect of this is water influx which increases sand production. The current practice in the industry involves the determination of the sand production potential and when the formation will fail to know if sand control will be needed and type of well completion. One way employed by production engineers is limiting the production rates such that sand production is avoided. Analogy with other wells in the same area or field and well testing technique – such as Drill Stem Test (DST) – are also used. Gravel packing is a well completion sand control method widely used in sand prone formations.

A known method of predicting sand production is the determination of formation strength mostly from core test analysis and or log derived in-situ stresses from leak off test and overburden density data which are applied in a failure mechanism. The applicability and accuracy of some of these models can be confusing. Also, the results from these models may not be representative of production conditions. However, the prediction from these models improves with more accurate input. Predicting sand production is not an exact science. It is important for practicable techniques that can be easily applied on the field to be developed to enhance hydrocarbon field development taking into consideration the mechanisms causing sand production. Most publications include largely the formation strength in developing their models indicating the importance of this factor. A need to put other factors to better estimate the sand production potential such that the restrictions of utilizing numerous cores testing analysis can be by passed. Maximizing the rate of returns on investment is the ultimate in the oil and gas industry; therefore from the economical point of view the overall effect of implementing a method(s) of sand control during well completion should be analyzed.

1.4 Objectives and Significance of Study

The objectives of this study are as follows:

1. To review state of the art sand prediction, control, and management techniques.
2. To develop effective methodology for sand prediction, control, and management.
3. To develop a step-by-step practical approach to sand prediction, control, and management.

The methodology is as follows:

1. Literature reviews on the subject matter.
2. Summary of these technical material and highlight of important parameter(s) affecting sand prediction, control and management.
3. Integrations of these three; sand prediction, control, and management to develop a new practical approach to manage sand production.

1.5 Organization of Thesis

The thesis is divided into five chapters. Chapter One gives a brief introduction and literature review on the subject matter. It also states the objectives and defines the scope and methodology used. Chapter Two talks about sand production effects, prediction, control, and management techniques. The development of effective methodology for sand prediction, control, and management is discussed in Chapter Three. Chapter Four focuses step-by-step new practical approaches to manage sand production. Chapter Five gives contains summary, conclusions, and recommendations of the thesis.

CHAPTER 2

THEORETICAL BACKGROUND OF SAND PREDICTION, CONTROL AND MANAGEMENT

2.1 Introduction

Sand production is a problem encountered during the production of oil and gas especially in formations relatively young in geologic age. These rocks are unconsolidated and accounts for majority of the world's reservoirs, therefore most formations are susceptible to sand production. It can be defined as the production of quantifiable amount of sand particles along with reservoir fluids. Sand production is a two-part decoupled phenomenon: sand must be separated from the perforation tunnel (failure), and the flowing fluid must transport the failed sand. Stress, controlled by drawdown and depletion does the first, and rate, also controlled by drawdown does the second (Venkitaraman et al., 2000). Depletion and drawdown fail the medium under either shear or tensile or volumetric failure mechanisms or a combination of them (Nouri et al., 2003). The production of formation sand might start during first flow or later in the life of the reservoir when pressure has fallen or water breaks through. Sand production can erode downhole equipment and surface facilities, production pipeline blockage and leakage, generate additional need for waste disposal which could be a problem in areas of stringent environmental regulations, lead to formation subsidence in severe cases and generate more frequent need for workovers and well intervention. These effects can be viewed as economic and of safety hazards in the oil and gas industry.

2.1.1 Sand Production Effects

The effects of sand production are often detrimental to the productivity of a well in the longrun. Downhole equipment might be blocked or damaged and/or surface facilities disabled.

1. Erosion of downhole and surface equipment: sand produced with formation sand at high velocity can erode surface and downhole equipment leading to frequent maintenance to replace such equipment. Blast joints, tubing opposite perforations, screens or slotted liners not packed in the gravel pack installation are potential sites for downhole erosion. If the erosion is severe or occurs over a sufficient length of time, complete failure of surface and/or

downhole equipment may occur, resulting in critical safety and environmental problems as well as deferred production. High-pressure gas containing sand particles expanding through the surface choke is the most hazardous situation. For some equipment failures, a rig assisted workover may be required to repair the damage (William and Joe, 2003)

Fig. 2.1: Surface choke failure due to erosion by formation sand (Source: Completion tech., 1995)

Fig 2.2: Eroded piston head (Source: Han et al., 2011)

2. Formation subsidence: the cumulative effect of producing formation sand is collapse of the formation. Over time large volume of sand will be produced at the surface creating a void behind the casing. This void widens as more sand is produced. Formation sand or shale above the void may collapse into it as a result of lack of material for support. The sand grains rearrange to create a lower permeability than was originally especially in formations with high clay content or wide range of grain sizes. Complete loss of productivity is likely in situations where the overlying shale collapses. The collapse of the formation is particularly important if the formation material fills or partially fills the perforation tunnels. Even a small amount of formation material filling the perforation tunnels will lead to a significant increase in pressure drop across the formation near the well bore for a given flow rate (Completion tech., 1995)
3. Sand accumulation in surface equipment: in situations where the production velocity of the reservoir fluid is sufficient to carry sand up the tubing to the surface. Sand particles often settle in surface facilities as separators, heaters, pumps, condensers. As the accumulation builds to appreciable volume in these facilities; equipment(s) cleanup becomes inevitable. This causes deferred production (well is shut-in) and additional cost is inquired as a result of the cleanup activity. Production capacity of the separator is reduced if partially filled with sand. This is as a result of its reduced ability to handle gas, oil and water.
4. Subsurface accumulation: when the production flow velocity is not sufficient to carry the sand particles to the surface. The sand accumulates in the casing or bridges off in the tubing, with time the production interval might be filled with sand. This reduces the production rate for such wells which might eventually cease as the sand accumulation makes it impossible for production to continue. Work over actives is often required in such occurrences for the well to resume production. If sand production is continuous, well clean out operations may be required regularly. This causes increased maintenance cost and lost production which in turn reduces returns from the well.
5. Sand disposal: this constitutes a problem in formations producing sand especially in areas where there are stringent environmental constrains. Offshore processing systems that do not satisfy anti-pollution regulation the separated sand is to be transported onshore for disposal constituting additional production cost.

2.1.2 Causes of Sand Production

Factors influencing the tendency of a formation/ well to produce sand can be categorized into rock strength effects and fluid flow effects. Production of sand particles consists of formation fines and load bearing solids. The production of formation fines which is not considered as part of the formations mechanical framework is beneficiary as can they move freely through the formation instead of plugging it. Production rates are often kept to levels so as to avoid the production of the load bearing particles, in many cases however low production rates are uneconomical. These factors include:

1. Degree of consolidation: The ability to maintain open perforation tunnels is closely tied to how strongly the individual sand grains are bound together. The cementation of sandstone is typically a secondary geological process and as a general rule, older sediments tend to be more consolidated than newer sediments. This indicates that sand production is normally a problem when producing from shallow, geologically younger tertiary sedimentary formations. Such formations are located in the Gulf of Mexico, California, Nigeria, French West Africa, Venezuela, Trinidad, Egypt, Italy, China, Malaysia, Brunei, Indonesia and others. Young Tertiary formations often have little matrix material (cementation material) bonding the sand grains together and these formations are generally referred to as being "poorly consolidated" or "unconsolidated". A mechanical characteristic of rock that is related to the degree of consolidation is called "compressive strength". Poorly consolidated sandstone formations usually have a compressive strength that is less than 1,000 pounds per square inch (Completion tech., 1995).
2. Production rate: Increasing the well production rate creates large fluid pressure gradient near the wellbore (perforation) which tends to draw sand into the wellbore. Generally, production of the reservoir fluids creates pressure differential and frictional drag forces that can combine to exceed the formation compressive strength. This indicates that there is a critical flow rate for most wells below which pressure differential and frictional drag forces are not great enough to exceed the formation compressive strength and cause sand production. The critical flow rate of a well may be determined by slowly increasing the production rate until sand production is detected. One technique used to minimize the production of sand is to choke the flow rate down to the critical flow rate where sand production does not occur or has an

acceptable level. In many cases, this flow rate is significantly below the acceptable production rate of the well."(Completion tech., 1995).

3. Pore pressure reduction: Reservoir fluid production overtime depletes the reservoir pressure resulting in pore pressure reduction. As the reservoir pressure is depleted throughout the producing life of a well, some of the support for the overlying rock is removed. Lowering the reservoir pressure creates an increasing amount of stress on the formation sand itself. (Completion tech., 1995) i.e. the effective overburden pressure increases. The formation sand particles may be crushed or break loose from its matrix at some time in reservoir life which could be produced along with the reservoir fluids. The formation might subside if the effective stress exceeds the formation strength due to compaction of reservoir rock from reduction in pore pressure.
4. Reservoir fluid velocity: The frictional drag force exerted on the formation sand grains is created by the flow of reservoir fluid. This frictional drag force is directly related to the velocity of fluid flow and the viscosity of the reservoir fluid being produced. High reservoir fluid viscosity will apply a greater frictional drag force to the formation sand grains than will a reservoir fluid with a low viscosity. The influence of viscous drag causes sand to be produced from heavy oil reservoirs which contain low gravity, high viscosity oils even at low flow velocities. (Completion tech., 1995)
5. Increasing water production: Increase in water cut increases sand production or as water production beings sand production beings too. These occurrences can be explained by two mechanisms. In a typical water-wet sandstone formation, some grain-to-grain cohesiveness is provided by the surface tension of the connate water surrounding each sand grain. At the onset of water production the connate water tends to adhere to the water produced, resulting in a reduction of the surface tension forces and subsequent reduction in the grain-to-grain cohesiveness. The stability of the sand arch around the perforation has been shown to be limited greatly by the production of water resulting in the production of sand. An arch is a hemispherical cap of interlocking sand grains that is table at constant drawdown and flow rate preventing sand production (Jon Carlson et al., 1992). A second mechanism by which water production affects sand production is related to the effects of relative permeability. As the water cut increases, the relative permeability to oil decreases. This result in an increasing pressure differential being required to produce oil at the same rate. An increase in pressure

differential near the wellbore creates a greater shear force across the formation sand grains. Once again, the higher stresses can lead to instability of the sand arch around each perforation and subsequent sand production (Completion tech., 1995).

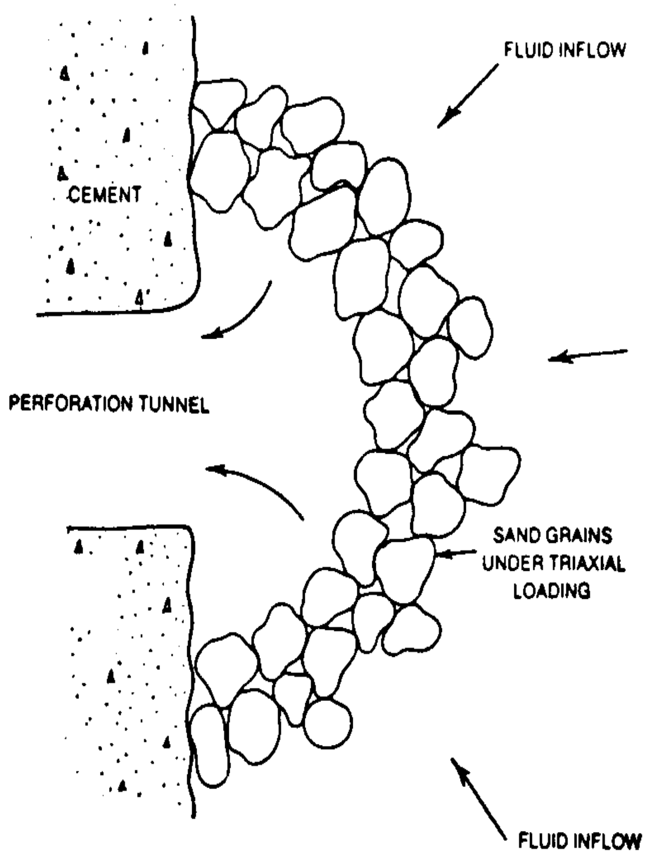


Fig. 2.3: Geometry of a Stable Arch Surrounding a Perforation (Source: Completion tech., 1995)

2.2 Sand Prediction

It is important for the completion engineer to know under what conditions a well produce sand to predict if the well will require a method of sand control. Sand prediction is usually done at the initial stage of reservoir development. It involves development of completion design, reservoir management strategy, perforation strategy, sand monitoring strategy, planning of the surface facilities and field economics. This task is not an easy one as the process of sand prediction is more of art than a science. At best performances of nearby offset wells are observed or the well is completed conventionally and flowed to observe if sand production will occur. The many published techniques to predict the onset of sanding can be categorized into four basic approaches: Empirical methods using field observations and well data, Laboratory simulation, Numerical methods and Analytical methods (Qui et al, 2006). Often two or more techniques are used in combination for prediction.

2.2.1 Empirical Methods Using Field Observations and Well Data

This technique uses a correlation between sand production well data and field operational parameters in prediction. Typically one or a group of parameters are used to evaluate the sanding potential and to establish a benchmark for sanding or no sanding. This is due to the practical difficulties of monitoring and recording several year worth of data for all the wells involved in a study (Veeken, 1991). Parameters such as Porosity, drawdown or flowrate, compressional slowness etc. are often used. Veeken et al., (1991) presented a list of the parameters that may influence sand production.

Table 2.1: Parameters Influencing Sand Production

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
- Heterogeneity

COMPLETION

- Wellbore orientation, wellbore diameter
- Completion type (open hole/perforated)
- Perforation policy (height, size, density, phasing, under/overbalance)
- Sand control (screen, gravel pack, chemical consolidation)
- Completion fluids, stimulation (acid volume, acid type)
- Size of tubulars

PRODUCTION

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

In its simplest form, the field data based sand prediction tool uses only one parameter. Examples include avoiding porosities higher than 30% (Bellarby, 2009), using a cut-off depth criterion for the installation of sand control measures in several deltaic environments: sand control is not installed below a certain depth. A depth of 12,000 ft and 7,000 ft were mentioned by Tixier et al and Lantz et al respectively. This critical depth is regionally dependent. Another example is applying a compressional sonic wave transit time **(Δt_c)** below which sand control is not required; the limit $\Delta \mathbf{t_c}$ is again field or regionally dependent and may vary from 90 to 120 μs/ft (Veeken et al, 1991). Tixier et al., 1975 derived a log based technique using mechanical properties log to predict sanding. A limit value for the sonic and density log derived parameter ratio of G (the dynamic shear modulus) to c_b the bulk compressibility i.e. (G/c_b) was established. When G/c_b exceeds 0.8*10 psi ^{2}, no sanding problem is expected. At ratios less than 0.7*10 psi ^{2} sand influx will occur. This mechanical properties log method works 81 % of the time (Osisanya, 2010) but seems to be dependent on regional environment too. The one parameter method is practical but conservative.

The two parameters method considers the depletion of the reservoir pressure (ΔP_{de}) and the drawdown pressure (ΔP_{dd}) not accounted for in the one parameter model. Stein et al., (1972) provided a method to estimate the maximum production sand free rate from density and acoustic velocity log data by relating drawdown to the dynamic shear modulus, E_s. Data from wells producing sand were used to relate to new wells.

$$(P_R - P_W)_C \propto E_s \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

$$[(P_R - P_w)_C]_Z = [(P_R - P_W)_C]_T \left[\frac{(E_S)_z}{(E_S)_T}\right] \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2)$$

On the basis of data from many fields Veeken et al., (1991) plotted the total drawdown pressure, ($\Delta P_{td} = \Delta P_{de} + \Delta P_{dd}$) versus sonic transit time, Δt_c, for sand and no-producing sand wells. From the plot shown in fig 2.4, a risk region possible to produce sand was established. To the left of the region, sand-free production can be realistically expected. It was also inferred that increasing total drawdown may trigger sand production. The position of the risk region is field dependent and its position can be determined from sand production tests or routine monitoring.

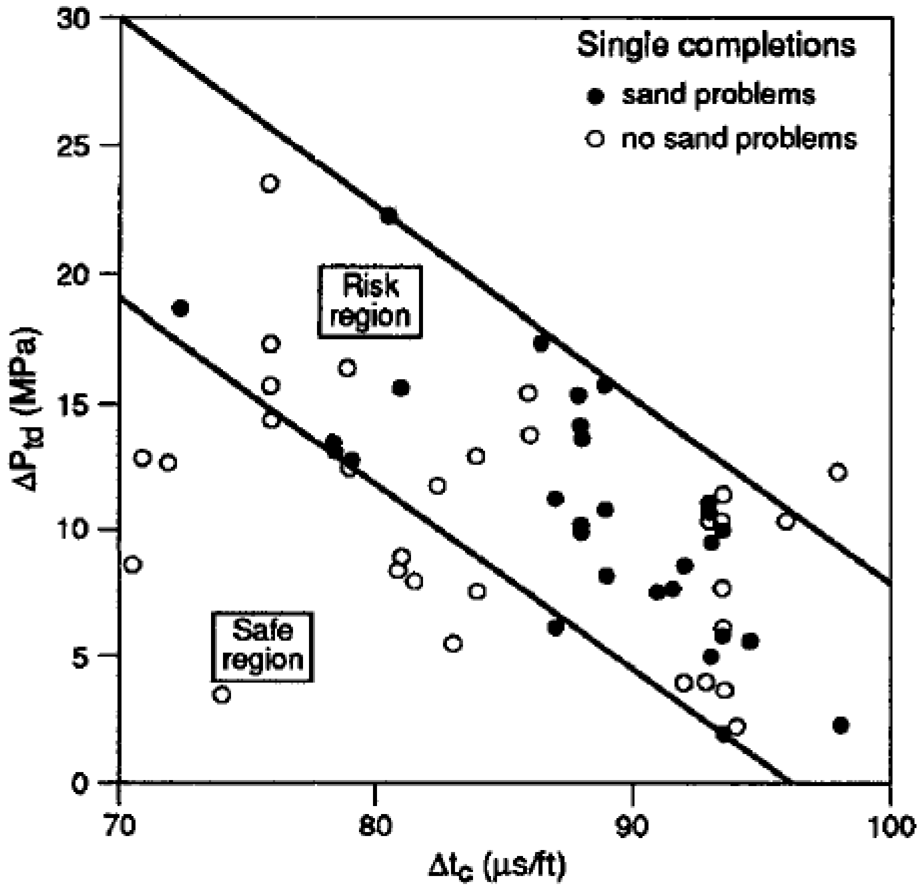


Fig 2.4: Total drawdown versus transit time for intervals with and without Sand problem

To improve the resolution between sand and no sand producers multiple parameter correlation can be used. Fig 2.5 shows the use of the multiple discriminant analysis technique for the data set of Fig. 2.4. Sand production is correlated with a wide range of parameters including depth, sonic transit time, production rate, drawdown pressure, productivity index, shaliness, water cut and gas cut. The sand and no-sand producing wells are well separated. The parameter influencing sand production most in case of Fig. 2.5 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, Ghalambor et al., used multiple linear regressions to correlate the critical drawdown pressure observed in water-producing gas wells with seven parameters (Veeken et al., 1991). Extensive data requirement limits the use of the multi-parameter techniques. Empirical methods have the advantage of being directly related to field data and can use easily measurable parameters to provide routine and readily understandable method to estimate sanding risk on a well by well basis. However, revalidation and recalibration of the approach is needed with data from the new environment when transferred from field to field. This necessitates large data acquisition for the new field that may involve field tests and laboratory measurements (Qui et al, 2006).

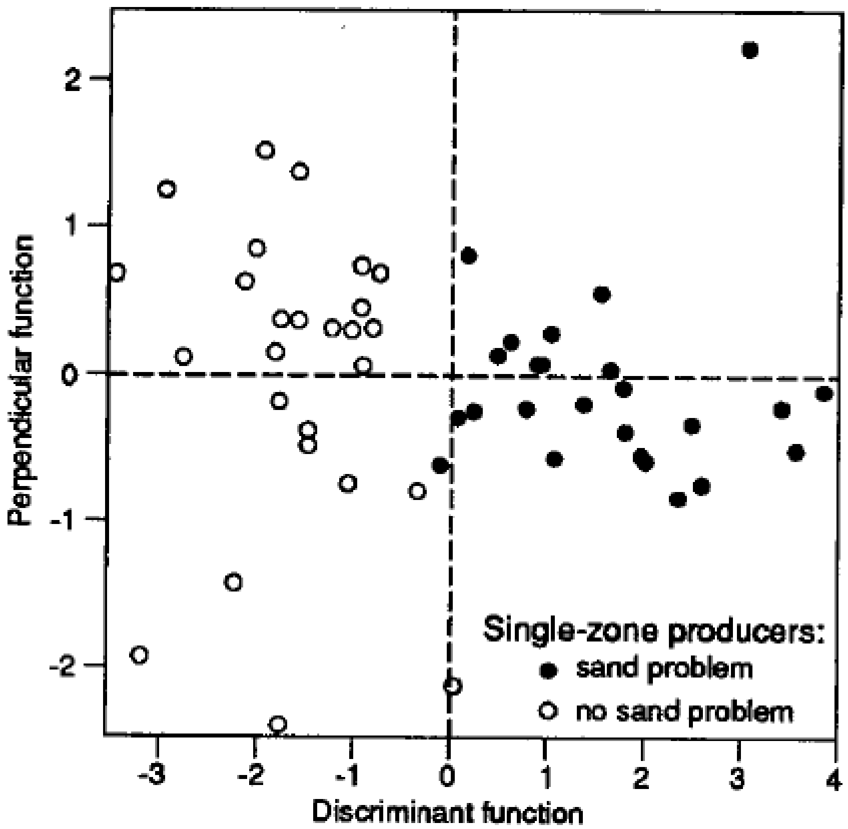


Fig. 2.5: Plot Showing Result of Multiple-discriminant Analysis

2.2.2 Laboratory Simulation

This approach is also used widely to establish correlation between the risk of sanding and measurable parameters like stress, flow rate and rock strength and to develop an insight into the mechanism of sanding in the formation involved. Laboratory experiments involve the use of available reservoir core samples or outcrop rock samples (with similar mechanical properties). Two types of laboratory sand production are common: laboratory sand production experiments and hollow cylinder collapse tests (Qui et al, 2006). Typically, laboratory experiments formulates sand production phenomenon in a controlled environment. Laboratory sand production test involves the use of cores to produce a small-scale simulation of flow through perforations or cylindrical cavities contained within a stressed cylindrical core sample. The technique offers the investigation of factors such as drawdowns, stress boundary conditions, flow rates, water cuts and rock properties. Expected conditions during the producing life of the well can be chosen as test parameters. This method is widely used to calibrate and validate predictions from analytical and numerical models. However, considerable number of cores and well equipped facilities are needed for the test.

Thick wall cylinder tests (TWC) are also used for sanding evaluation and calibration, easier to perform than sand production test. In this tests a hollow cylindrical core plug is loaded axially and laterally under increasing hydrostatic stress ($\sigma_1=\sigma_2=\sigma_3$) until collapse occurs in the walls of the cylinder. The hydrostatic stress at which failure initiates in the internal wall is reported as the TWC-internal and the stress that causes external wall failure is called TWC External or TWC collapse. The external wall catastrophic failure pressure corresponds to the perforation failure condition that causes continuous and catastrophic sand production. The internal wall failure pressure is less than the catastrophic failure and normally corresponds to the onset of transient sanding. TWC internal can be defined by an increase in fluid volume expelled during constant loading or by monitoring and measuring the internal hole deformation during tests using internal gauged or camera. However, such measures require large plug sizes which are not routinely available (Khaksar et al, 2009). BP reports using plugs that have a 1.5 in. outside diameter (OD), a 0.5 in. internal diameter (ID) and are 3 in. long (Willson et al., 2002b), whereas Shell use plugs that have a 1 in. OD, 0.33 in. ID and are 2 in. long (Veeken et al., 1991), (Bellarby, 2009). Results from TWC test can be used to predict the depths and conditions at which sanding might occur in the field, if the stresses corresponding to failure are considered representative of stresses at the sandface or perforation cavity. Veeken et al, (1991) gave a relationship between the near-wellbore vertical effective stress ($\sigma_{v,w}$) and the TWC collapse pressure (σ_{twc}) from many experiments carried out on friable-consolidated sandstone.

$$\sigma_{v,w} = 0.86 \times \sigma_{\text{twc}} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots.. (3)$$

The results from TWC can however be influenced by sample size/hole size ratio of the hollow cylinder.

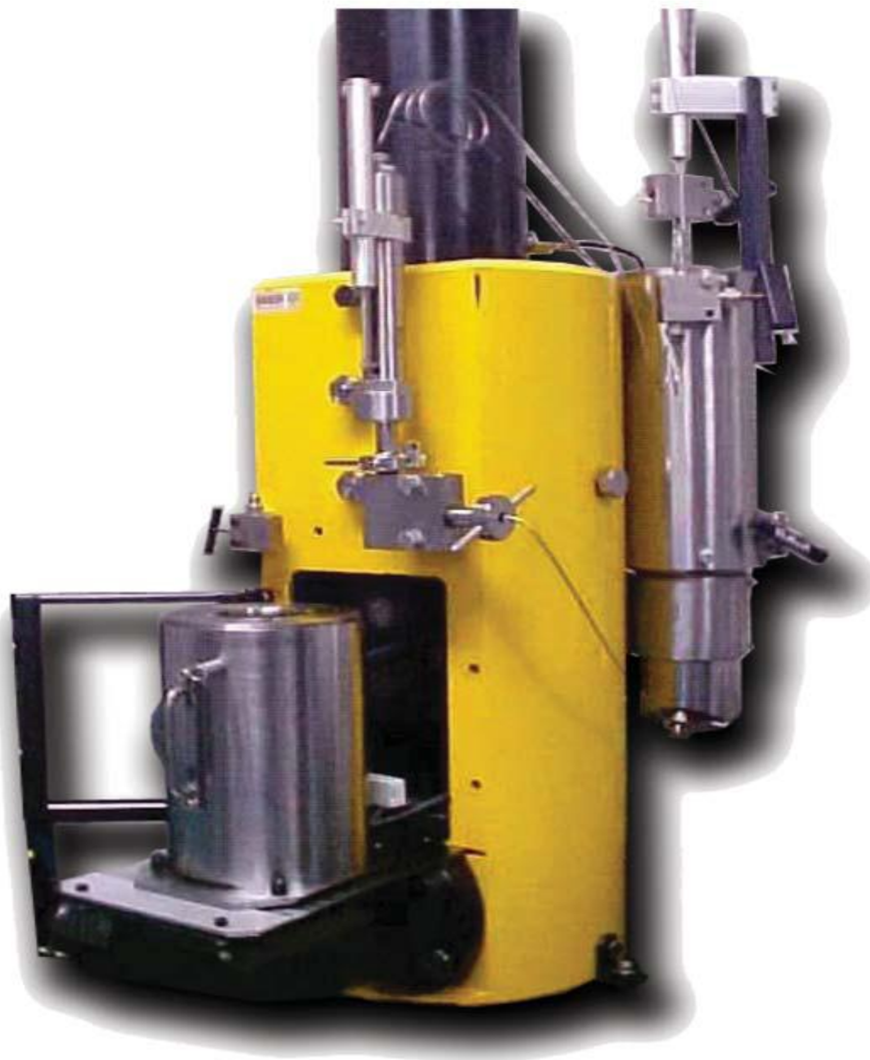


Fig. 2.6: TWC machine (Source: Bellarby, 2009)

From laboratory experiments important findings as stresses and rock strength are dominant factors controlling sanding initiation and sand production, flowrate only plays a role in in weak and unconsolidated rocks and rocks under excessive stresses, increase in drawdown causes sand production increase, due to changes in boundary conditions (i.e., stresses of fluid flowrate) bursts of sand production are frequently observed after which sand production may gradually decline to some background, there are significant nonlinear scale effects related to the size of a perforation or open hole and their stability against sanding, with smaller diameter cavities being most stable (Qui et al, 2006) have been reached. In the 1970s, Exxon conducted an experiment to establish the relationship between the rock compressive strength and sand production potential of the rock. The studies revealed that the rock failed and began sand production when the fluid flow stresses exceeded the formation compressive strength. As a rule of thumb from the research, sand production or rock failure will occur when the drawdown pressure is 1.7 times the compressive strength. Fig 2.7 shows the equipment used in the test to determine the magnitude of the pressure drops that core samples could withstand before sand production starts. This relationship holds for consolidated formations. Non-destructive test like impact and scratch test are also used for measuring the strength properties of a rock.

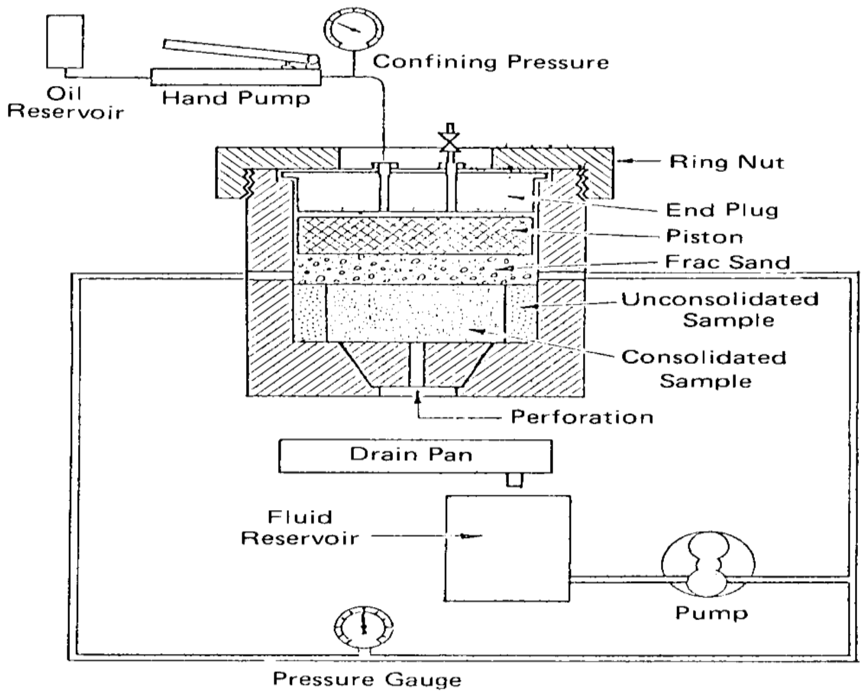


Fig. 2.7: Exxon Equipment for Drawdown-to-Rock Failure Test

The main disadvantage of this approach is the amount and availability of core samples needed, time and cost for preparing the core, conducting the experiments, processing and analyzing the data from the test. A question of how well a laboratory simulation represents on field scenarios is also raised.

2.2.3 Analytical Methods

This method has gained more popularity in the petroleum industry due to its computational simplicity, readily implementable calculations, and the ease of running multiple realizations to compare many different scenarios. Analytical sand prediction models are based on modeling of perforations and production cavity stability. This tool requires a mathematical formulation of the sand failure mechanism. Production cavity stability under producing conditions is related to the stresses imposed on the formation matrix and the complex manner in which the matrix accommodates these stresses. Stresses imposed are due to overburden pressure, pore pressure, flowing fluid pressure gradient near the wellbore, interfacial tension effects and viscous drag forces. At the mechanical failure of the load bearing sand grain matrix sand is assumed to be produced. Prediction accuracy depends more on how the rock constitutive behaviour is modeled, the failure criterion chosen and whether the materials and other parameters affecting the rock failure are determined precisely. Moore, (1994) highlighted some engineering and geologic parameters (Table 2.2) to be considered in a complete evaluation of the sand production potential of a formation based on different sand prediction models and techniques available in the industry. However, no single sand prediction method can accommodate all data highlighted in table 2.2 reason being that the process of data aquisition is extensive and such information are not available during field development .

Table 2.2: Data Required in a Complete Evaluation for Predicting Sand Production Potential

1. Field data
2. Cyclic loading
3. Directional in-situ stresses
4. Quality of cementation
5. Perforation geometry and spacing
6. Perforation cavities geometry and shot density
7. Cavity evolution effect of varying perforation geometry
8. Well pressure
9. Flow rate (fluid forces)
10. Permeability, viscosity, and relative permeability for two and three phase flow
11. Rock deformation characteristics
12. Rock strength characteristics
13. Flow through porous media where non-Darcy flow is included
14. Log-derived rock mechanical properties
15. Laboratory tri-axial measurements of core samples
16. Regional tectonic forces

The process of sand production starts with the mechanical failure of rock near the wellbore. Sand particles become loose from the formation matrix due to shear opening of the rock and become available to be transported by formation fluid to the wellbore. This process is governed by the formation intrinsic strength and the effective in-situ stresses at that depth in the formation. Once the sand grains are loose, the rate and amount of erosion of the matrix depends on factors such as production rate, the fluid velocity and the fluid viscosity (Navjeet, 2004). The mechanisms responsible for sand production (i.e. sand failure mechanisms) are:

1. Compressive or Shear failure
2. Tensile failure due to pressure drawdown
3. Erosion or Cohesive failure due to cementation degradation

2.2.3.1 Compressive or Shear Failure

Compressive failure refers to an excessive, near cavity wall, tangential stress which causes shear failure of the formation matrix. Compressive failure occurs predominantly in consolidated sandstones (Veeken et al, 1991). Shear failure condition can be triggered by far-field stresses (depletion) and drawdown pressure. Rock strength criterion plays an important role in sand production from shear failure. Shear strength consists of two components; cohesion or physical bonds between the adjoining sand grains and friction. As a result of shear failure, reduction in hole size due to plastic failure near the perforation tunnel might occur. Around the perforation tunnel a stress concentration field is established. This stress concentration field causes the rock to respond either elastically as in strong formation or yield (weak formation), in which case a plastic zone is developed around a perforation tunnel. Large and small sand grains are generated and formation starts deteriorating at the failure plan once shear failure occurs.

Various failure criterions can be used to predict the shear failure mechanism of a rock. Among which are Von Mises, Drucker-Prager, Mohr-Coulomb, Hoek-Brown, Modified Lade and Modified Weibols & Cook. The choice of the failure criterion can be guided by a laboratory experiment to understand behaviour of the rock. The Mohr-Coulomb criterion is the most widely used for shear failure prediction. This criterion considers only the effects of the maximum and minimum principal stresses. It postulates that the failure occurs when shear stress on a given plane within a given plane within the rock reaches a critical value given by:

$$\tau = C + \sigma_n \tan\theta \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (4)$$

Where, τ is the shear strength, psi

σ_n is the stress normal to the failure plane, psi

C is the cohesive strength, psi

θ is the internal friction angle, degrees

The equation consists of two components; cohesion (C) and friction ($\sigma_n \tan \theta$). Cohesion failure produces the sand particles while shear failure breaks the rock along the shear plane. Assumed material behaviour for shear failure models include: linear elastic brittle, elastic plastic.

2.2.3.2 Tensile Failure

Tensile failure refers to a tensile radial stress exceeding the tensile failure envelope and is triggered exclusively by drawdown pressure. From the tensile failure criterion when a fluid flows into a cavity at high production flow rates, tensile net stresses can be induced near the cavity resulting in formation failure. The mechanism of tensile failure occurs at the perforation tunnel; here the radial stress is controlled by the reservoir pressure and wellbore pressure. Sudden pressure changes can exceed the tensile strength of the formation, causing sand production and subsequent enlargement of the perforation tunnel. Tensile failure may occur at the perforation tip or the perforation wall which is usually penetrating within the plastic zone (Navjeet, 2004). Weingarten and Perkins, 1995 studied the conditions necessary for formation stability around a spherical cavity in weakly consolidated rock. An equation describing tensile failure condition using pressure drawdown, formation rock cohesion and frictional angle was derived. They provided dimensionless curves for determining the pressure drawdown at a specified wellbore pressure.

2.2.3.3 Erosion or Cohesion Failure

Erosion refers to a gradual removal or production of individual sand particle from the cavity surface (perforation tunnel, wellbore surface in open-hole completion etc.). Erosion is controlled by the cohesive strength. Erosion will take place if the drag force exerted on a surface particle exceeds the (apparent) cohesion between surface particles. The frictional drag is directly related to the velocity of the fluid flow. Hence, fluid velocity becomes an important parameter. This is confirmed by field experience: in loosely consolidated formations sand production from open holes tends to be less than from perforated completion: in line with the fact that the fluid velocity at the open hole surface is three orders of magnitude smaller than the velocity at the (intact) perforation surface. Erosion is related to tensile failure, but needs to be considered as a separate mechanism due to its particulate nature (Veeken et al., 1991).Analytical approach captures the mechanisms of sand production, they can be implemented and calibrated more easily compared to numerical. Important aspects of sand production captured by analytical approaches are: stresses, rock strength, in-situ stresses. The time and effort needed for analyses are reduced and overcomes the difficulties of obtaining complex input parameters are overcome by analytical methods.

2.2.4 Numerical Methods

These are finite element analysis models that incorporate the full range of formation behaviour during plastic, elastic and time-dependent deformation. Numerical models provide a detailed description of the stress state and can be accurate. In comparison to other methods of prediction, numerical method is regarded as superior because it accounts for more factors influencing rock failure and sand production. However, the main disadvantage of the method is its complexity and time consumption. Time, resources and data needed for the method might not be available. When properties needed in the numerical modeling are assumed or approximated due to lack or real data, results from the complex modeling are not necessarily more accurate or reliable than that from other approaches that uses simpler easily accessible data.

Another method used in sand prediction is the analogy or historical method. This relies on production experiences such as rate, drawdown, water-cut etc. from other wells in the same reservoir or nearby fields (offset data) to arrive at a choice between sand control and sand prevention. The most critical factors to determine the sand production potential of a reservoir formation are (1) formation strength (2) in-situ stresses (3) production rate. Formation intrinsic strength is however the key information needed. Zhang et al., 2000 developed a simple and efficient approach to evaluate formation strength. They found out to construct a universal failure envelope the only parameter needed is the critical pressure. Conventional logs data (compressional wave velocities) can be used to obtain the failure envelope of a sandstone formation. The generality of their observation is still explored. The failure envelope is constructed from the p_c determined.

$$p_c = 10.086 \times In \frac{(6.789)}{12.322 - V_p} \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots . (5)$$

Where,

$p_c = critical\ pressure$ (psi)

$V_p = compressional\ velocity$ (ft/sec)

2.3 Sand Control

The concept of sand control is based on the absolute exclusion of sand; zero tolerance of sand production at the surface. Problems associated with sand production have provided justification for downhole sand control devices. Once it has been established through sand prediction that at the desired production rate the reservoir will produce sand. The question of the best completion practice to mitigate sand is raised. The choice of the sand control method to be used in a reservoir depends on operating practices, conditions of the field (formation sand characteristics), successful field experiences and economic considerations. Traditionally, the main classes of sand control techniques are mechanical and chemical. Available sand control techniques in the industry include:

1. Rate control or exclusion
2. Non-impairing completion techniques
3. Selective perforation practices
4. Screens (without gravel packs)
   - Slotted liners
   - Wire-wrapped screens
   - Premium screens
   - Expandable screens
   - Pre-packed screens
5. Gravel packs
6. Frac packs
7. Chemical sand consolidation
   - In situ formation consolidation
   - Consolidated gravel

The techniques highlighted above can be further divided into two groups: mechanical exclusion methods and arch stabilization methods (Najveet, 2004). Arch stabilization methods can be further divided into natural arches and reinforced arches. Classification of the above sand control methods given by Najveet, (2004) are presented in table 2.3. The mechanical exclusion methods are designed to prevent sand production through bridging type retention or filter type retention. Bridging type retention allows a certain quantity of sand production until a bridge is formed against a filtration medium such as a screen or sized gravel or the two in combination (e.g. gravel packs). These bridges are disturbed easily by abrupt changes in production rate, resulting in sand production until a new bridge forms. In filter type retention sand production is excluded, and does not depend on the formation of bridges. Filter type sand control is attained simply by further reducing slot size of the screen and size of gravel, below that required for bridging type retention (Najveet, 2004). Mechanical sand exclusion methods highlighted in table 2.3 are listed in order of effectiveness and reliability in providing filter type sand control.

Table 2.3: Sand Control Methods Classification

Mechanical exclusion (listed in order of increasing effectiveness and reliability)
Consolidated gravel (filling perfs only)
Screens alone
Consolidated gravel (filling perfs & wellbore)
Pre-packed screen
Expandable screen
Gravel packing
Frac packing
Arch stabilization
Natural arches
Non-impairing completion techniques
Selective perforating
Rate control
Reinforced arches
In situ chemical formation consolidation

Arch stabilization depends on the formation of stable arches near the wellbore to prevent sand production. Natural arch stabilization is produced by avoiding arch destabilizing actions that can induce sanding. Stability of natural arches is sensitive to changes in flow rate. Reinforced arches are produced using chemical bonding agents such as plastic resin etc. to create new bonds and strengthen existing ones between adjoining sand grains. Often a combination of techniques is used to ascertain reliability of sand control. Such situation may occur when the parameters of the well exceed the design applicability of a specific control method.

2.3.1 Rate Control or Exclusion Method

Treating the well with care by minimizing shocks to the reservoir is a method used by operators to control sand production. Laboratory and field experience has shown that reducing production rates and pressure drawdown reduces sand influx. Cook et al., (1994) established the influence of flow rate on sand production. The procedure is to slowly and in small increments reduce or increase the rate/drawdown until an acceptable level of sand production is reached or identifying a threshold of rate/drawdown sand can be produced. The objective of this technique is to obtain a maximum flow rate that will allow the formation of a stable arch at the wellbore. Finding a maximum flow rate has to be repeated overtime as reservoir conditions changes (e.g. pressures, fluid saturation). Rate exclusion method is generally more effective when little sand has already been produced.

Rate control is used as both a temporary and a permanent method of sand control. It is used temporarily pending installation of a more effective sand control method, when the value of continually deferring production greatly exceeds the cost of installing an effective sand control method. In the case of high-pressure gas wells, rate control may be utilized temporarily until reservoir pressure has declined to the point where the well control risks which will be incurred during sand control installations are acceptable. Permanent use of sand control as a sand control method usually results when the cost of a more effective sand control method cannot be justified or is not operationally feasible. Rate control may be suitable in situations where production rates must be limited anyway to control water influx or gas coning. A common use of rate control occurs in deep gas wells producing from consolidated sandstones (Navjeet, 2004). The limitation of rate control method in high permeability formation is that flow rates required to enable formation of stable sand arches is often less than the flow potential of the well and may represent not favour well economics in terms of productivity. Rate control is utilized more at the later life of the well when sand production begins largely due to pressure decline and high water cuts.

2.3.2 Non-Impairing Completion Techniques

Drilling and completion activities could damage or impair the new wellbore formation through the influx of drilling of completion fluids etc. into the formation. Indirectly, this technique can be considered a method of sand control especially in marginal sanding situations. High pressure drawdown may lead to premature formation failure in a marginal sand producer. This is because a higher drawdown is needed in impaired formation to produce the same rate of fluid from the reservoir as an unimpaired formation. If a formation is noticed to fail as a result of excessive drawdown, it is fairly often attributed to impaired formation. It has been noted that wells that produced sand during drill stem test, when formation impairment was removed through appropriate completion techniques produced sand free. Completion considerations of significances include the use of clean, filtered non-damaging completion fluids together with proper stimulation design, and treatment. Well stimulation method as acidizing can cause problems if not well designed. In situations where the only method of sand control to be used is passive such as rate control, an unimpaired formation becomes essential in minimizing sand production.

2.3.3 Perforating

Cased and perforated completions are the basis of many fields. Perforating a well is to establish good flow communication between the wellbore and the reservoir. This is more common in onshore fields but also exist in offshore areas. The productivity of a well where applied is largely dependent on the perforation design. Perforation parameters affecting well productivity include perforation dimensions (diameter and penetration), phasing, shot density and charge type. The perforation dimension is a function of the perforating charge/gun design and quality, the position of the gun/charges in the wellbore when they are fired, and well conditions such as temperature, pressure, well fluids, casing size and metallurgy, cement and formation properties (Navjeet, 2004). The aim of most cased-hole completions is to generate the maximum perforation length- deep penetrating charges. Damage caused as a result of perforation impairs productivity. The explosive energy of a perforation creates a hole by outward pressure.

This pressure crushes the cement and rock. The cement and rock are not destroyed in the process, but they, along with parts of the perforation assembly, end up inside the perforation. They must be removed for the perforation to be productive. If not removed it results in a larger pressure drop at the perforations that can contribute to tensile failure.

Most of this debris will be crushed/fractured rock, with minor amounts of charge debris. There are a number of ways of removing this damage. Flowing of the well after perforating will create a drawdown on all the perforations. This will flow some of the debris from some of the perforations (Bellarby, 2009). It is important for perforation impairments to be minimized in order for production stresses which tend to cause sand production are minimized. For sand control further cleanout is imperative prior to gravel packing, frac packing or injecting consolidating chemicals (Completion tech., 1995). The objective in gravel packing is to have large diameter perforations which have been well cleaned, leaving an open cavity where gravel can be placed.

Perforation cleaning is necessary in order to remove perforation damage as a result of formation crushing and compaction, drilling mud, cement, dirty completion fluids and perforating gun debris. Perforation cleaning can be accomplished by underbalanced perforating and perforation washing. Perforating at underbalance allows the production of the sand during the initial stages and thus avoids having to manage transient sand production during later stages of well production (Venkitaraman et al., 2000). Perforation washing is a widely used method for removing perforation damage. It entails pumping through each perforation with sufficient pressure and rate because it is essential to maintain circulation to remove debris from the well. A clean fluid system or fluids with surface filtration systems or a combination of both can be used in washing. In soft rock completions, once communication is established between two or more perforations, debris is removed from the perforations by washing out a void behind casing. In gravel packed completion, this void is subsequently packed with highly permeable gravel. Perforation washing is better suited for long intervals. It is important to remove damage which is not removed by other cleaning processes. A common practice in completions is to acidize the perforations after other perforation cleaning techniques have been used, immediately prior to gravel packing (Navjeet, 2004), frac packing or injecting consolidating chemicals.

2.3.3.1 Selective Perforating

In heterogeneous formations, rock strength varies substantially with depth among the different lithologies present. Avoiding perforating weaker sections of the formation, sand free production rates throughout the life of the well can be maintained. Higher critical drawdown can be gotten perforating the strong zones (have higher degree of cementation). Unfortunately, these weaker sections are often the main productive zones than stronger intervals having lower permeability. To allow draining of the reservoir, the formation should have good vertical permeability such that fluids from the weaker sections can flow to the stronger sections. Both productivity analysis using nodal analysis programs and strength analysis (using cores, logs etc.) need to be carried out prior to making this decision (Venkitaraman et al., 2000).

2.3.3.2 Overbalanced Perforating

This method of perforating simplifies well control because fluid inside the casing overbalances formation pressure and prevents inflow. Perforating through this method holds also holds debris necessitating additional clean-out operation as mentioned above. A new method of extreme overbalanced perforating or surging with resin has been successfully used by Oryx Energy in both their onshore and offshore wells (Navjeet, 2004). This method of extreme overbalanced perforating and stimulation provides a means to sand control. Another advantage is the combination of perforating with sand control as a single operation reduces the completion fluid volume requirements and the average time to complete the well. Extremely overbalanced perforating and stimulation could cause the industry to reconsider the method of perforating wells for sand control. The overbalanced perforating method resin method is used in a wellbore suspected of producing sand in its life and the overbalanced surge resin method is used when the casing has existing perforations in a wellbore suspected of producing sand.

2.3.3.3 Oriented Perforating

Laboratory tests in the past have indicated that the mechanical stability of perforation cavities depends on perforation direction relative to the in-situ stress field. This led to the idea of oriented perforating to minimize the shear stresses acting at the wall of the perforation cavities (Completion tech., 1995). In regions where there is a large contrast between the in-situ stress field perforation should be oriented in the direction of the maximum stability. Oriented perforation guns can be used to perforate only in one direction, thereby delaying or avoiding sand production. In extensional stress regimes, for example, many sedimentary basins, the maximum stress will be in the vertical direction (Bellarby, 2009). Oriented perforations in the direction of maximum horizontal stress in a vertical well increase the probability of more stable perforation tunnels for a perforated only completion. Thus, eliminating the need for conventional sand control (Najveet, 2009).

This method can be used successfully in fields with economical constrains. Oriented perforating uses 180° phasing shot in the direction of maximum perforation stability. The use of 180° phasing is believed to reduce the risk of sand production due to a reduced probability of hitting the most unfavourable perforation direction. In case of horizontal completions, the dominant stress field will be vertical or overburden. In this completion, the perforations are directed to the top and bottom of wellbore to the maximum stress field (Najveet, 2009). A challenge is the determination of the maximum horizontal stress direction in a field. There always arises a factor of uncertainty in stress orientation and magnitude as determined in the field.

2.3.4 Screens

All forms of screen can be run in either a cased hole or open hole well with or without gravel packing, although each will have its optimum environment. Screens can also be run into open hole with a pre-installed, pre-drilled liner to provide additional installation protection (Bellarby, 2009). The simplest and oldest sand control method employs only a screen to restrain sand production (Navjeet, 2004). This control method is relatively low-cost. When used alone as sand exclusion devices, the slotted liners or screens are placed across the productive interval and the formation sand mechanically bridges on a slot or opening (Completion tech., 1995) before excessive sand production, screen plugging or erosion occurs. There are several rules available for screen sizing. Normally, the slot width or the screen gauge should be sized to equal the formation sand grain size at the largest 10 % level. Coberly presented this sizing criterion (Navjeet, 2004). The 10^{th} percentile or D_{10} designation denotes the sieve size (screen) which would retain 10 % of the sand grains. The remaining 90 % of the formation sand will be allowed to pass through it. Bridging theory shows that particles will bridge against a hole if the hole diameter does not exceed about three particle diameters. The bridges formed will not be stable and may breakdown from time to time when producing rate is changed or the well is shut-in (William and Joe, 2003).

Bridge break down can cause the formation sand to be resorted (finer sands and silts may be trapped between the coarser grains) which over time tends to result in plugging of the screen. The risk of screen cutout especially in formations that produces fine sand can be minimized by slowly bringing the well through the critical sand producing rate. Screen-alone applications generally should be limited to the producers that meet the Coberly's criterion and open-hole completions, particularly horizontal wells or wells with extremely long completion intervals (Navjeet, 2004). A non-standard application of screens is for keeping marginal, minor sand influx out of sensitive wells e.g. high-rate gas wells. The main concerns of the application of screen-alone are erosion failure and the plugging of perforation tunnels especially in cased completions. Though the screens alone offers the lowest cost of downhole filtering, the over evaluation in terms of cost should factor in cleanout and workover etc. costs.

2.3.4.1 Slotted Liners

Slotted liners have the largest holes of all the screens. They are usually less costly than wire-wrapped screen, they have smaller inflow area and experience higher pressure drops during production. Slot width usually ranges from 0.012 in. to 0.250 in., these slots are made by a precision saw or mill longitudinally. Slotted liner completion is to guide against hole collapse while maintaining the well productivity (Igbokoyi, 2011). Slotted liners plug more readily than screens and are often used in low productivity wells and where economics cannot support the use of screens. Three types of slotted liners are available:

1. Perforated liner where holes are drilled in the liner.
2. Slotted liner where slots of various width and depth are milled along the liner length.
3. Prepacked liners for unconsolidated formation.

2.3.4.2 Wire-Wrapped Screens

They have smaller openings than slotted liners. They are used often in gravel pack and standalone completions. They are made up of a base pipe with holes, longitudinal rods and a single wedge-shaped wire wrapped and spot-welded to the rods as shown in fig. 2.8. Wire-wrapped screens do have substantially more inflow area. They are made from stainless steel and are resistant to corrosion and erosion, an advantage over slotted liners. The smallest slot size used is 0.002 in. or 50 microns with 50-70 mesh gravel. As with slotted liners, they are widely used in horizontal wells.

Fig. 2.8 Wire-Wrapped Screens (Source: Bellarby, 2009)

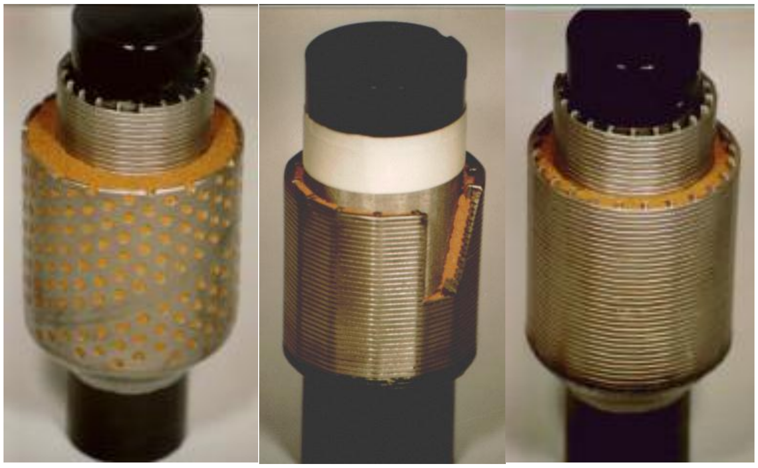
2.3.4.3 Premium Screens

This refers to screens constructed with a woven mesh and some form of shroud for protection. A variety of different designs from vendors exist. Premium screens are made up of multiple woven layers meaning they have non-uniform apertures. They are thinner than pre-packed screens but slightly thicker than wire-wrapped screens. They typically have an inflow of about 30%. Due to their more robust construction they are used in harsh environments- long, horizontal, open-hole wells (Bellarby, 2009). Example of premium screens is presented fig. 2.9.

Fig. 2.9 Example of a Premium Screen (Source: Bellarby, 2009)

2.3.4.4 Pre-packed Screens

These are similar in construction to wire-wrapped screens, but with two screens. Pre-packed screens consist of an inner screen assembly with a layer of resin coated gravel placed around it making up the annulus and an outer screen. The size of the screen slots are made such that they prevent the escape of gravel packed between the screens. Pre-packed screens offer a degree of depth filtration, and the relatively high porosity over 30 % combined with their very high permeabilities provide minimal pressure drops (Bellarby, 2009). However, they can be prone to plugging due to finer sands embedding between the pore throats. They will plug more easily than a wire-wrapped screen (William and Joe, 2003).



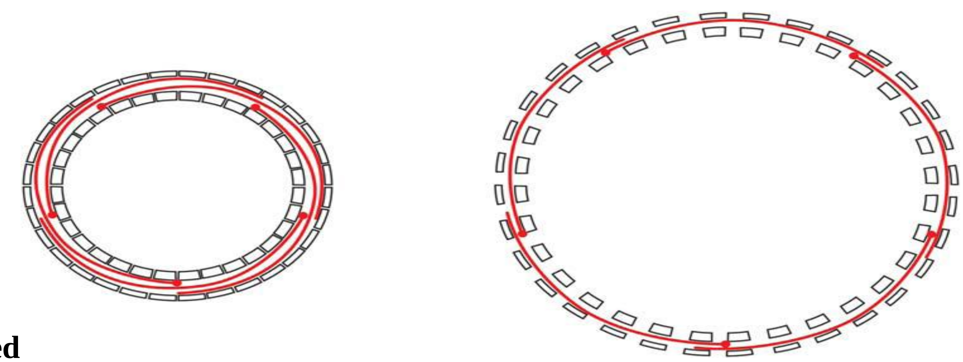
(a) (b) (c)

Fig. 2.10 (a) Single-Screen Pre-pack (b) Slim-Pak (c) Dual-Screen (Source Completion Tech.)

2.3.4.5 Expandable Screens

An expandable screen is made up of three layers: (1) a slotted base pipe, (2) a filtration medium and (3) an outer protective shroud. It expands when a cone is pushed through the screen. The design of expandable screens offers it a lot of unique advantages. It offers a lager internal diameter than any other type of screen; ESS eliminates the annular space between the screen and the sandface. Thereby stabilizing the sandface and minimizing sand movement, hence sand production. Productivity of Expandable screens completion is generally superior to other sand control methods especially when deployed in open hole and offer the advantage of near well-bore access for well interventions operations if it becomes necessary during well life (Ayoola, 2009). Expandable screens are widely used in horizontal open-hole completions. Its greatest drawback is its susceptibility to collapse in squeezing formations.

Fig. 2.11 Expandable screen (expanded) (Source: Bellarby, 2009)



Unexpanded

Expanded

Fig. 2.12 Overlapping mesh design for expandable screens (Source: Bellarby, 2009)

2.3.5 Gravel Packing

Gravel packing is the most widely used sand control technique used in the industry. It accounts for about three-quarters of treatments (Jon Carlson et al., 1992). A gravel pack is a downhole filter held in place by a properly sized screen with the gravel pack sand holding the formation. In gravel packing, slurry of accurately sized gravel is pumped into the annular space between a centralized screen and either a perforated casing or open-hole. The gravel pack is designed to prevent the production of formation sand. The flow path of the gravel pack must be small enough to prevent the production of sand but large enough to accommodate well productivity. This technique is a relatively expensive method of sand control, but it is the most effective method of stopping sand movement while permitting production. Gravel packing is not without its drawbacks which are majorly the increased complexity of completion operations and further reducing operating wellbore diameter. Subsequently, downhole operations are complicated and operational flexibility decreases. To obtain an effective gravel pack system, the pack must be properly designed using the correct gravel size, gravel thickness, correctly positioning the liner and placing the gravel.

Selection of the proper gravel size is based on sand sieve analysis on sand samples representing the formation. These can be conventional cores, side-wall cores or sand samples obtained from perforation washing or produced. The early work on gravel packing was done by Coberly and Wagner, (1938) where they suggested using the gravel size of 10 times the D_{10}, of the formation sand (Bellarby, 2009) i.e. using larger sand grains in sizing determination. Another criterion used is the Saucier's based on laboratory experiments. He concluded that between 5 and 7 times the median (D_{50}) particle size, the ratio of gravel pack to sand permeability was a - peak regardless of the permeability sand (Bellarby, 2009). Six times the D_{50} is been used widely in the industry. However, these are not rigid guidelines, testing of formation sample will give the best result. Of importance to optimize the gravel packed completion is the gravel quality, gravel packing fluids, choice of screen or liner selection.

There are three basic methods of gravel packing methods: (1) Inside Casing Gravel pack (ICGP) (2) Milled Casing Underreamed Gravel Pack (MCUGP), and (3) Open Hole Gravel Pack (OHGP). In ICGP, a screen is placed across a perforated interval. The annular space between the casing and screen likewise the perforations tunnels are packed with gravel. With ICGP multiple completion are simplified and workover activities and zone repairs are possible. Inside casing gravel packs have some advantages over milled casing underreamed gravel packs. In highly deviated holes milling problems can occur. Remedial cementing to control Gas Oil Ratio and water influx is not possible once a window has been cut in MCUGP. Influx of formation fines into the gravel and perforation tunnels, causing permeability reduction hence increased drawdown is a main disadvantage of ICGP. This subsequently reduces productivity index (PI).

MCUGP better ensures good productivity by eliminating flow restrictions and increased radial extent of the gravel pack. However, in selecting candidates for MCUGP care must be taken because it can be regarded as a permanent completion. Therefore, gas-oil contact and water-oil contact are of interest and should be isolated by 20 ft from the underreamed section. The main advantage of MCUGP is that it offers improved oil flow geometry, increased effective filtration surface due to radial extent gravel, and no perforation debris. For Open hole gravel packs the casing is placed above the top of the pay zone. They are performed on the bottom zones of the wells especially used for initial completion where the geology of the formation is well known. Open hole gravel packs completely avoid the difficulties and concerns of perforation packing, and reduce the gravel placement operations to the relatively simple task of packing the screen/open hole annulus (Completion tech., 1995). Its productivity and reliability is like as in MCUGP. Cased-hole or inside gravel packs now prevail as an accepted industry practice since they offer flexibility, selectivity, and effective zonal isolation and are usually easier to install (Navjeet, 2004).

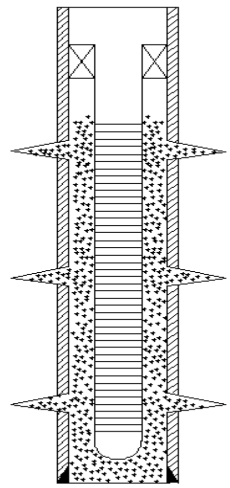


Fig. 2.13 Open Hole and Cased Hole Gravel Packs (Source: Completion tech., 1995)

2.3.6 Frac Pack

Frac pack is like an internal gravel pack but the pumping is done above the fracture pressure of the formation (Navjeet, 2004). At this pressure the rock splits open generating a fracture which bypasses the near wellbore damage often present in gravel packs. Frac packing helps increase the contact area with the reservoir thereby increasing productivity. Frac packs are poorly suited to intervals close to gas contacts or where cement quality is poor. Compared to cased hole gravel packs, frac packs require more complex fluids, larger volumes, higher pump rates, plus the associated mixing and pumping equipment (Bellarby, 2009). Proppants are used to fill the fracture.

2.3.7 Chemical Consolidation

Chemical consolidation refers to a method that employs a liquid resin which is injected from a well-bore into the unconsolidated rock surrounding the well. The resin is catalytically polymerized to form a porous, permeable rock mass. With most resins, it is necessary to inject a displacement fluid, which is a fluid following the resin which is not miscible with the resin (Talaghat et al., 2009). Three types of commercially available resins include: furans, epoxies, and phenolic resins. Historically chemical consolidation has been used as a low-cost method of stopping sand production in short perforated intervals. It is generally considered a remedial option (Bellarby, 2009). Short intervals with low likelihood of producing sand, low consequence of producing some sand, chemical consolidation can be used as a substitute for screens. The objective in sand consolidation is to increase cementation between the sand grains whilst maintaining permeability. By this, the completion interval behaves like a natural completion without any mechanical sand control equipment obstructing the completion interval. Chemical consolidation can be subdivided into two categories: (1) in-situ consolidation, (2) resin-coated gravel

2.3.7.1 In-situ Consolidation

The formation near the wellbore is treated with resin to cement the sand grains together at their points of contact. This is done by injecting liquid resins through the perforations into the formation and the flushed by a catalyst. The resins used are epoxy, furan and phenolic resins. The success of in-situ consolidation depends on the permeability of the consolidated sand mass to reservoir fluids, the degree of consolidation should not decrease with time. In-situ consolidation treatments are of two types: phase separation systems and overflush systems. Phase separation systems contain only 15 to 25 % active resin in an otherwise inert solution. Overflush systems contain a high percentage of resin (Completion tech., 1995). Clays attract the resin; therefore clay concentration hinders the effectiveness of the consolidation process. Clay stabilizers are often used as pre-flush. In-situ consolidation poses less damage to the formation than that can occur from gravel packing. Due to difficulties in achieving effective placement, high cost of resins, likewise compatibility and contamination problems the use of this method of sand control is limited. To decide the best choice of resin for a sandstone experiments should be conducted.

2.3.7.2 Resin Coated Gravel

This is gravel pack sand coated with a thin layer of resin with high permeability. The gravel is circulated typically via coiled tubing inside casing and perforations or open hole and then squeezed to form a plug across the production zone. The resin coating hardens and bonds adjacent particles together strengthening the pack. The bottomhole temperature of the well or injection of steam causes the resin to cure into a consolidated pack. After curing, the consolidated gravel pack sand can be drilled out of the casing leaving an unobstructed wellbore. The remaining consolidated gravel in the perforations acts as a permeable filter to prevent the production of formation sand (Completion tech., 1995). An advantage of resin-coated gravel is that it doesn't need any special hardware. But a significant additional pressure drop that might affect productivity is created by the pack. This technique is often used in place of regular gravel in gravel packed completions so as to minimize formation or gravel movement. Intervals longer than 20ft are difficult to cover completely. This technique represents about 5% of sand control treatments, mainly concentrated on low-cost onshore markets (Jon Carlson, 1992).

2.4 Sand Management

Sand management refers to an operating concept which does not normally apply the traditional sand control means and production is managed through monitoring and control of well pressures, fluid flow rate and sand influx. More recently sand management is been applied to all processes, technologies and completion techniques meant to address the issue of producing fluids from weak formation (Mathias, 2003). Sand management in conventional oil and gas production has been implemented on a large number of wells in the North Sea and elsewhere. In almost all cases it has proven to be workable, and has led to the generation of highly favorable well skins because of self-cleanup associated with the episodic san bursts that take place (Completion tech., 1995). These wells experience high productivity index and subsequently high production rates. Sand management also cuts the expensive sand control equipment. However, sand management involves risk management. Sand management techniques commonly used in the industry include Rate exclusion, selective perforation practices, orientated perforating (these have been mentioned above under non-exclusive/passive sand control technique) and sand monitoring techniques which include Acoustic transducers, sand detectors, and choke inspection.

CHAPTER 3

EFFECTIVE METHODOLOGY FOR SAND PREDICTION, CONTROL AND MANAGEMENT

3.1 Introduction

Sand production is a problem encountered in most fields producing from unconsolidated reservoirs. It has been established that asides the natural tendencies of these formations to produce sand due to less compaction other factors come into play. These include pressure depletion, degree of loading and unloading, and water breakthrough. Tackling the problem of sand production entails the integration of sand prediction, control and management a shift of paradigm from just looking at a section. This ultimately involves team work of the drilling, completion, reservoir and production engineer, through best field practices. Getting right the sand prediction cannot be overemphasized as it forms the basis of well optimization in terms of overall cost and productivity. Sand prediction can be likened to a decision tool which directs the choice between sand control (exclusive) or sand management (passive). Depending on the tolerance risk of sand production in a particular reservoir the choice of sand management is made. Consolidated and friable reservoirs experience sand production latter in the productive life of the reservoir relative to unconsolidated formations where sand production is experienced early. Therefore it is essential to understand the characteristics of the formation before deploying/implementing a sand control or management technique. The new methodology of alleviating sand production focuses on using drilling operation, correlating between available prediction methods, using accurate data with little uncertainties in sand prediction.

3.2 Sand Prediction Methodologies

Formation sand prediction study should answer the question, will the formation produce sand, rate or volume of sand production and time of likely sand production. If not all at least two these questions should be answered. The integration of the various techniques of sand prediction results in an effective prediction. Therefore, to effectively predict sand production the following methodologies are given:

Mechanism causing sand production: Of importance is the knowledge of the mechanisms involved in sand production especially one can be more dominant in a formation. These will help in the approach of prediction. For example if the reservoir's oil water contact is high (i.e. close to the surface or payzone), then there is high probability of water influx initiating sand production. Various factors believed to influence the production of sand has been given and mentioned in table 2.1. The factors are classified into three segments formation, completion and production. These include: reservoir depth, permeability, rock strength, flow rate, pressure drawdown to mention a few. It is however impossible to include all these in a prediction method due to non-availability of data at the time of field development. Three factors have been earmarked to be critical in sand prediction namely: formation strength, production rate and in-situ stresses. Sand prediction involves the modeling of formation failure mechanism which is related to these three parameters. The type of formation (consolidated, friable or unconsolidated) principally governs the likely failure mechanism discussed in chapter 2. At this point, all data informing about the formation is gathered. These include offset well data (production data, drilling, completion etc.), geological information, coring, rock properties and logging data etc. Data to inform on in-situ field stresses are gotten; overburden stress from formation density evaluation or by simply applying a gradient of 1.12 psi/ft to the depth in question (Craig et al., 2007), minimum horizontal stress from extended leak-off tests (XLOT), maximum horizontal stress (σ_2) from minimum horizontal stress (σ_3) and overburden stress (σ_1) or assumed to be identical i.e. $\sigma_3 = \sigma_2$. Table 3.1 presents typical formation densities.

Table 3.1- Typical Formation Densities (Craig et al.)

Material	Density (g/cc)	Overburden (psi/ft)
Sandstone	2.323	1.01
Shale	2.675	1.16
Limestone	2.611	1.13
Dolomite	2.899	1.26
Halite	2.323	1.01
Granite	2.691	1.17
Average	**2.587**	**1.12**

Formation classification: The understanding of the type of formation the reservoir sits should be the first step to formation sand prediction. These helps to either classify the reservoir as either consolidated or unconsolidated. Morita et al., (1991) in their work presented typical sand producing formations. The information they provided helps understand different formation behavior in terms of sand production and can be utilized in formation classification for prediction purposes. It is common knowledge that sand production is peculiar to unconsolidated reservoirs, therefore firsthand information that the formation will likely produce sand is gained. This can be detected from acoustic or sonic sand log travel time (Δt). Adjacent shale barriers to sandstone indicate the degree of consolidation. A consolidated sand is well compacted, and can be identified with a sonic or acoustic log travel time (Δt) in the shales less than or equal to 100 µs/ft. In unconsolidated sands the travel time (Δt) is greater than 100 µs/ft. Veeken et al., 1991 gave a range below which sand control is not required (sand does not occur) as between 90 - 120 µs/ft. This varies from field to field or region to region.

Porosity: Formation property as porosity can be used prediction. Formations with porosity between 30 -34 % are mostly unconsolidated with high probability of producing sand. Porosity can be determined from cores and well logs. If the porosity is lower, sand control is not necessary in such formations.

Analogy method and/or field history: A green field utilizes analogy method, while a new well to be drilled in an existing field can utilize information from analogies and field history. This is because the field already has existing wells; experience from such wells is transferred to the new well. This method provides firsthand information which gives an insight of what to expect from the reservoir. Offset well data from other wells in the same horizon, field or depositional environment is used to predict the sanding potential the reservoir. Deductions especially from the production data and type of completion used in such environments are useful. This approach requires similarities between the fluid types, rock properties, flow rates and pressure drawdown from all wells. Data already acquired is used in making this comparison.

Drill Stem Test (DST): This involves individual well testing through DST. The reservoir is flowed under conventional completion to determine its sanding potential. The well is flowed at gradual increasing flowrates through the chokes until sand is produced or a maximum acceptable rate in which the reservoir can be produced is derived. Based on this a sand free production rate can be established and completion decision in terms of sand control can be made.

Comparison of drawdown to compressive strength: The formation rock strength gives a measure of how consolidated (hard) a formation is. The reservoir pressure drawdown can be related to the compressive strength of the reservoir. The work of Exxon shows sand production occurs when the drawdown is 1.7 times the compressive strength.

Well logs: They provide a continuous profile of the formation data as they are made in-situ. Sonic, density and neutron log serves as indicator to porosity and rock strength which is important in prediction. These are then used to derive elastic rock properties such as Poisson ratio, Young's Modulus, Bulk modulus and shear modulus which is subsequently used in prediction.). Tixier et al., (1975) derived a log based technique using mechanical properties log to predict sanding. A limit value for the sonic and density log derived parameter ratio of G (the dynamic shear modulus) to c_b the bulk compressibility i.e. (G/c_b) was established. When G/c_b exceeds 0.8×10 psi ^{2} no sanding problem is expected. At ratios less than 0.7×10 psi ^{2} sand influx will occur. Formation rock strength is the most crucial information for sanding predictions and sand control decisions. This can be evaluated from well log data and calibrated with laboratory test results. Log-derived measurements provide a profile of the strength through the reservoir. The log derived and core corrected Unconfined Compressive strength (UCS) is often corrected to Thick wall Cylinder (TWC); they are considered more representative of the formation strength around a perforation tunnel. Dynamic elastic rock properties gotten from logs are corrected to static conditions to further represent the reservoir. Dynamic Young's modulus $E_{dynamic}$ and Poisson's ratio $v_{dynamic}$can be calculated from measured compressional and shear wave velocities V_p and V_s using;

$$E_{dynamic} = \frac{\rho_b V_s \left(3V_p^2 - 4V_s^2\right)}{V_p^2 - V_s^2}$$

$$v_{dynamic} = \frac{V_p^2 - 2V_s^2}{2\left(V_p^2 - V_s^2\right)}$$

Various correlations exist to correct the dynamic properties to static properties. Care should be taken in using these correlations as they apply more to some areas than others. The work of Khaksar et al., (2009) clearly lists the correlations of various authors with areas most appropriate for use (Appendix).

At this stage, it is ensured that cores are available for rock mechanics test and are representative and ideally preserved. Core samples should be taken when sampling for petrophysical test to avoid using cores that has deteriorated or slabbed i.e. with lots of anomalies.

Laboratory technique: The laboratory test technique of sand prediction is extensive and time consuming. It provides the best rock mechanics parameters used in prediction because of its reliability. They are used to calibrate the log-derived strength models. Various laboratory tests have been talked about in chapter 2. Tri-axial test used to build the Mohr-Coulomb failure criterion (established rock failure envelope) can be carried out and augmented with non-destructive rock strengths.

Supplementary testing: These are techniques and tests performed on core samples which supplement the rock strength data. This is because sandstones can be composed of many types of minerals and rocks with individual strength which are can be accounted for through supplementary testing. The principal methodologies of these techniques include Special Core Analysis Laboratory (SCAL) and petrographic analyses. These should be incorporated for use in a laboratory rock strength test program. They give more information on the core samples and answer the question why some phenomenon takes place during testing. For example pore infilling and grain coating minerals which provide the arch stabilization effect of failed zones may exist in the formation. These tests are:

- Scanning Electron Microscopy (SEM)
- X-Ray Diffraction (XRD)
- Cathode- Luminescence Microscopy (CL)
- Particle (or grain) Size Distribution (PSD) analyses
- Thin Section (TS) analysis/ point counting (petrographic microscope)

The Geomechanical model for the field is calibrated with drilling incidents such as losses, breakouts, and stuck pipe. This is done to reduce the uncertainty in geomechanical parameters gotten.

Model selection: Theoretical/Analytical sand prediction tools are based on theoretical modeling of perforation and cavity stability. Simple Mohr-Coulomb which assumes rock behaves elastically under stress is often used in the industry. Hoek-Brown, Drucker-Prager failure criterion can also be used. These have been discussed in chapter two. The selection on the model type to be used in prediction (sand production risk quantification) should be based on best fit for purpose with acceptable accuracy bearing in mind the limitation from unavailability of data. This is why Finite element techniques are not often used because time, money and data requirements do not justify their complexity. Sand prediction models often relate sand production to safe/critical drawdown rates, flowrates, volume and time. The prediction model should answer the question if and how much. The model is then calibrated with available field data/histories from offset wells to remove conservatism.

Quantifying uncertainties: this involves quantifying uncertainty of the deterministic result from the prediction model. As mention before uncertainties are inherent in inputted data in the model. Monte Carlo using @risk can be used to perform this simulation for the intervals of interest. Correct Probability Distribution Functions (PDF) of the model input parameters must be modeled into the simulation. Quantifying uncertainties give some level of confidence in risk

Sensitivity Analysis: This is to determine to what extent the results of the model is sensitive to each input parameter. This will govern the accuracy of obtaining such parameter(s).

3.3 Sand Control Selection

The choice of this approach is dependent on sand prediction and risk associated with sand production. It will be uneconomical to manage amount of sand produced, therefore sand control. This is often the resort in unconsolidated reservoirs where sand production is experienced sooner than later. Sand control involves the fitting of downhole screens and slotted liners in completion, gravel packing or frac packs the well, and sand consolidation. These various methods were described in chapter 2. Operational risk or effects of sand production as mentioned in chapter 2 justifies the use of sand control. The initial completion must be selected based on a long-term prevention of sand production and not initial cost nor productivity. The overall cost of work overs, cleanout etc. that can be incurred during well productive life should be considered. Selecting the appropriate screen size or sand control to be used in sand control requires the knowledge of the formation grain size distribution. If in consolidated reservoirs, initial completion chosen should accommodate eventual installation of a sand control device. Methodologies for effective sand control are presented thus:

3.3.1 Drilling Practices

Non-impairing drilling and completion fluids should be used in drilling to avoid formation damage that can occur during drilling and completion of the productive interval. Drilling mud weight which prevents formation dilation should be used, drilling fluid that will maintain good hole cleaning, and less damage to the pay zone. Formation information from prediction study come into play here in selecting best drilling and completion fluids for the formation. Problem of excessive drawdown due to near well bore impairment as a result of drilling activities can be eradicated. Excessive drawdown to meet up economic or production demands has been highlighted as a factor influencing rock failure from chapter 2 (shear and tensile). The presence of impairments can result in difficulties like non- uniform placement of sand consolidation and gravel pack, or unnecessary localized produced fluid velocities.

3.3.2 Horizontal Well

Reservoir fluid velocity is one of the discussed mechanisms causing sand production as in chapter 2. The frictional drag force exerted on the formation sand grains is created by the flow of reservoir fluid. This frictional drag force is directly related to the velocity of fluid flow and the viscosity of the reservoir fluid being produced. Comparing with vertical wells, the mean flow velocities in a horizontal well is lower by the h_p/L where L is the horizontal length, and h_p is the perforated height in a vertical well. A horizontal well has been drilled and completed in an unconsolidated sand reservoir with a simple perforated liner. It has been operated for almost two years without producing any perceptible quantity of sand at the surface (Igbokoyi, 2011). Another important application of horizontal well is to minimize influx of unwanted reservoir fluid like water which has been mentioned as one of the factors causing sand production. Therefore, drilling of horizontal well helps in sand control.

3.3.3 Selecting Appropriate Sand Control Method

Sand control method selection is usually governed by formation sand characteristics. However, the information necessary for sand control method selection is obtainable from sand prediction model result, information from field history, wellbore and completion design, reservoir properties, design of surface facilities and project economics. In the selection of the appropriate sand screen fit for a formation, sand retention potential by physical testing is more reliable as characteristics such as uniformity and fines content can be seen. Core samples from rock failure test (laboratory test) can be used for this test. The choice of the screen to use is dependent on lowest pressure drop in combination with acceptable level of sand retention. Worthy of note in the selection a sand exclusion technique are expected problems from sanding. The work of Morita et al., (1991) is useful in this regard in addition to those discussed in chapter 2. The problems include:

1. Sand fill.
2. Formation Erosion.
3. Interruption of production.
4. Formation subsidence and wellbore Collapse.

3.3.3.1 Field History

The history of offset wells and nearby fields can be used in selecting a sand control method to implement. Evidence from these fields or wells might not be as effective as information from a sand prediction model, insight is provided as to formation characteristics and sand production history. The information thus provided can be used in selecting best fit sand control method. In cases where the field or wells understudied have reported history of sand production mitigated with some form of sand control, such approaches can be considered for implementation in new wells.

3.3.3.2 Wellbore and Completion Design

The selection of a sand control method can be determined from casing size (wellbore), well trajectory and completion types in terms of open hole or cased hole. Consolidated formations often employ open hole completions due to high degree of compaction. Traditionally used $4^{1}/_{2}$tubing is good for a successful sand exclusion method. Hole deviation has notable sanding effects on some sand exclusion techniques as screens, as they tend to erode more quickly. Various screens have been discussed in chapter 2 with their advantages and disadvantages. The one that best suits a formation can implemented as well as other sand control techniques.

3.3.3.3 Reservoir Properties

Reservoir properties as permeability, sorting, productive interval length, sand quality (presence of undesirable shale streaks), porosity, reservoir temperature and pressure can influence the choice of sand control method. Pre-packed screens offer a degree of depth filtration, and the relatively high porosity over 30 % combined with their very high permeabilities provide minimal pressure drops. Gravel pack is recommended for longer sand intervals, a narrow grain size distribution signifies a more effective gravel pack. Reservoir temperature and pressure effects does not necessarily affect sand control method selection except in cases of high temperature and pressure reservoirs where sand control is necessary.

3.3.3.4 Surface Facilities

Surface sand monitoring devices (twin-pot sand-filtering unit, acoustic sand detectors), device resistance to erosion (sever-service adjustable choke) and sand disposal often influences the selection of a sand control method. Materials used in surface facilities should be erosion resistant to a large extent and sand-monitoring devices installed to monitor sand production. Environmental constraints necessitating conscious means of sand disposal must be noted, such that sand disposal means is friendly. As mentioned in chapter two offshore, sand disposal can incur additional overhead cost.

3.3.3.5 Project Economics

Well economics is important in selecting a means of sand control. Worthy of consideration are initial sand control cost, completion repair cost (workovers etc.) and interrupted production (productivity loss). The remedial cost of sand control is often very high which could affect the profitability of the project in cases especially when well productivity is low. This high cost could be due to rig availability or the use of modern techniques as coiled tubing etc. An example is presented by in the work of Guinot et al., (2009); the gravel packing option appeared to be more costly, requiring both more equipment and additional rig time.

Some sets of guidelines for Sand control type selection based on field experience are presented in the tables below.

Table 3.2- Guidelines for Sand Control Method Selection (Nigeria Experience) (Rating for specific conditions when applied to new wells) (Source: Anon, (2011))

Special conditions	Gravel pack	Sand Consolidation	Resin Coated
Fine sand	Good	V. Good	Good (1)
Long interval	V. Good	Poor	Good
Multiple intervals	V. Good	Poor	V. Good (2)
Short interval	V. Good(3)	V. Good	V. Good
Permeability variation	V. Good	Poor	Good
No rig	N/A (4)	Good	N/A
Deviated hole	Good	Good	V. Good

(1) Longest interval treated to date is 16 feet. With perforation washing, zone lengths can be longer but are only limited by mixing blender capacity.

(2) When isolated and treated separately

(3) May be uneconomical

(4) N/A- not applicable

(5) The majority of the wells gravel packed with less than 10° deviation, although wells have been successfully gravel packed with deviation up to 50°.

Table 3.3- Guidelines for Sand Control Method Selection (Nigeria Experience) (Rating for specific conditions when applied to old wells) (Source: Anon, (2011))

Special conditions	Gravel pack	Sand consolidation	Resin Coated particles
Fine sand	Good (a)	Good	Good (a)
Long interval	Good	Poor	Good
Multiple intervals	Good	Poor	Fair (b)
Short interval	Good	Good (c)	Good
Permeability variation	Good	Poor	Good
No rig	N/A	Good (c)	N/A
Deviated hole	Good	Good (c)	Good

Stipulations 1 to 5 given in Table 1 apply here in addition to the following

(a) Correct gravel size very important.

(b) Possible communication between intervals

(c) Only if wells has produced little or no sand

3.4 Sand Management

Sand management involves tolerating some amount of sand production from the reservoir; here it is deemed okay to produce some sand particles with reservoir fluids. This requires planning of sand life cycle in terms of the production rate control, equipment monitoring for erosion and sand inspection, reservoir pressure maintenance, well bore cleaning and surface handling of sand and sand disposal. Sand management decision is based on the risk evaluation from sand prediction results. Perforation methods such as oriented perforating rely on accurate prediction of the in-situ stresses such that perforating is carried out in the right direction. If the quantity of sand can be managed then sand management is applied. Sand management approach safes the cost of installing expensive downhole sand control device. It has been successfully applied in producing heavy oil (Canada) at optimized flow rates and well productivity. Sand management methods include:

- Rate control method
- Perforation methods(selective perforation, oriented perforation, underbalanced perforation)
- Formation stabilization
- Sand monitoring and inspection
- Pressure maintenance
- Surface handling of sand
- Sand disposal
- Do-nothing approach

Some of these approaches have been discussed in previous chapter.

3.4.1 Sand Monitoring and Inspection

Sand monitoring and inspection forms an integral part of sand management. This is important because of safety risks, economic and environmental risks. Surface inspections for the presence of produced sand and its quantifying its effect in terms of erosional activities is important for formations where sand control is not installed. It forms a means of sand rate prediction and quantification which could be used in cases where the initial completion plan has to be reviewed. The well type or reservoir type dictates to a large extent the composition of the surface facilities to monitor and inspect sand production. Visual inspection method is often employed as the sand monitoring method. This involves choke inspection for erosion, sand traps inspection, separator and other surface facilities inspection for sand accumulation. Employed also in monitoring are erosional sand probes, acoustic sand detectors, batch monitoring, X-ray and ultrasonic inspection of surface facilities.

- Sand traps: used to carry out volumetric sand monitoring. Sand traps are installed usually at tees and bends to capture sand. The method does not provide real-time data as sand volume is measured by disassembling the sand trap after some time. Typical sand traps are separators. This method is however not efficient.
- Choke inspection: a more reliable sand monitoring and inspection method, the internals of choke are inspected for erosion or presence of produced sand. Visible is the effects of erosion on the choke likewise sudden change in production rates can indicate choke erosion.
- Fluid sampling: sampling reservoir fluid after primary separator is implemented in monitoring sand including centrifugation for water and sand cuts. This is the Bottom Sediment Water measurement (BS&W) done during appraisal well testing or normal production. Much sand usually remains in the primary separator and the method sensitivity cannot be guaranteed (William and Joe, 2003).
- Electronic sand detectors provide real-time sand production measurement capabilities and are mounted in or on flow lines. These include intrusive erosional probes, intrusive acoustic or sonic probes, and non-intrusive acoustic sand detectors. Intrusive probes are placed inside of the flow line downstream of the wellhead. Erosional probes use electrical resistance principle to monitor material loss as a result of sand erosion. Acoustic probes use the Piezo-electric effect to detect the noise created by impinging particles on the probe. Non-intrusive acoustic sand detectors also use the Piezo-electric effect; these are particularly attractive to subsea developments since they offer the possibility of Remotely Operated Vehicle intervention to allow servicing (Navjeet, 2004).
- X-ray and Ultrasonic inspections also monitors and indirectly, this method give qualitative measurement of sand production, real time measurement not available. X-ray method gives a two-dimensional picture of the whole section of flow line

.

3.4.2 Surface Handling of Sand

This refers to a process where a quantifiable measure of sand is allowed to be produced along with reservoir fluids. Mostly used in heavy oil formations where it is beneficial. This requires the effective use of sand handling techniques bearing in mind the risk of sand production. To be considered in employing this approach are sand disposal plan especially offshore and overall well operation cost. Here, it is important that the formation sand prediction is of high quality.

3.4.3 Do-Nothing Approach

This approach applies mostly in consolidated formations where sand production is not an issue. Used in this approach are cased and perforated completions as well as “bare-foot’ openhole completions. The initial completion cost is minimized using this approach but can be problematic when rock starts failing. Applications for these completions in sand-prone areas generally require low-rate shallow wells in land operations. Under these conditions, separators can be cleaned and wells bailed under routine field maintenance operations (William and Joe, 2004).

CHAPTER 4

STEP-BY-STEP PRACTICAL APPROACH TO SAND PREDICTION, CONTROL AND MANAGEMENT

4.1 Step-by-Step Sand Prediction, Control and Management Process.

Sand issues should be considered during the exploration and appraisal stages of a reservoir to identify productive intervals with the potential to produce sand. Depending on how severe the sanding potential is the choice of either sand control or management is made. It is important to bear in mind the whole concept of sand prediction, control and management in making field development decisions. Sand prediction affects the overall field or well development plan, hence recovery. Figure 4.2 depicts the application of sand prediction as a basis for major activities done for reservoir development. This chapter addresses the methodologies highlighted in chapter three. Table 4.3 presents fourteen steps developed as guide to ensure effective sand modeling process for reservoir development.

Table 4.1 Step-by-step Sand Prediction Procedure

Step	Activity
Step 1	**Formation evaluation process** • Assemble team of key personnel (Completion Engineer, Drilling Engineer etc.)
Step 2	**Plan to acquire extensive data fit for purpose of formation sand modeling process** • Offset well data • Drilling and Completion data • In-situ stress maps • Well log information • Core data
Step 3	**Carryout preliminary analysis on sand prediction using** • Analogy /field history • Formation classification • G/c_b • Comparison of drawdown to compressive strength

Step 4	**Acquire well data** • Logs • Core • Well incidents • Leak-off tests • Formation density logs
Step 5	**Estimate rock mechanical properties from acquired logs and cores i.e. all necessary parameters for prediction e.g. rock strength, Poisson ratio** • TWC, UCS or Tri-axial test • Supplementary test • Non-destructive test • Log analysis
Step 6	**Calibrate log-derived properties to lab-derived properties using** • Appropriate correlation based on formation characteristics
Step 7	**Calibrate geo-mechanical model against drilling incidents (breakouts, losses, stuck pipe)**
Step 8	**Select prediction model(s) based on** • Formation characteristics • Simplicity and versatility • Time and cost • Available data • Provide means of calibration
Step 9	**Calibrate model with field history and observation from well test (DST)**
Step 10	**Quantify uncertainties of deterministic sand prediction**

Table 4.2: Step-by-step sand Control Procedure

Step 1	**Assess possible sand production potential of the formation from prediction results** • Sand control applicability • Sand control not needed
Step 2	**Risk quantification to decide on sand management strategy (bear in mind sand production problems). On the basis of expected sand volume and /or rate**. • Exclusive sand control (Sand Control) • Sand management (passive)
Step 3	**Plan Sand control strategy** • Selection of sand control type using available guidelines, screening criteria, field history, reservoir properties etc.

Step 4	**Implement sand control** • Completion design (e.g. gravel selection, gravel quality, Gravel pack fluids, screens selection, gravel pack method and evaluation) • Well Preparation prior sand control treatment (perforation washing, clean drill pipe or tubing) • In consolidation perform (acidizing, preflush and formation injectivity test)

Table 4.3: Step-by-Step Sand Prediction, Control and Management Procedure

Step	Activity
Step 1	**Formation evaluation process** • Assemble team of key personnel (Completion Engineer, Drilling Engineer etc.)
Step 2	**Plan to acquire extensive data fit for purpose of formation sand modeling process** • Offset well data • Drilling and Completion data • In-situ stress maps • Well log information • Core data
Step 3	**Carryout preliminary analysis on sand prediction using** • Analogy /field history • Formation classification • G/c_b • Comparison of drawdown to compressive strength
Step 4	**Acquire well data** • Logs • Core • Well incidents • Leak-off tests • Formation density logs
Step 5	**Estimate rock mechanical properties from acquired logs and cores i.e. all necessary parameters for prediction e.g. rock strength, Poisson ratio** • TWC, UCS or Tri-axial test • Supplementary test • Non-destructive test • Log analysis
Step 6	**Calibrate log-derived properties to lab-derived properties using** • Appropriate correlation based on formation characteristics
Step 7	**Calibrate geo-mechanical model against drilling incidents (breakouts, losses,**

	stuck pipe)
Step 8	**Select prediction model(s) based on** • Formation characteristics • Simplicity and versatility • Time and cost • Available data • Provide means of calibration
Step 9	**Calibrate model with field history and observation from well test (DST)**
Step 10	**Quantify uncertainties of deterministic sand prediction result using Monte Carlo simulation** • @risk • Crystal ball • Sensitivity analysis on input parameters to enhance future studies
Step 11	**Assess possible sand production potential of the formation from prediction results** • Sand control applicable • Sand control not needed
Step 12	**Risk quantification to decide on sand management strategy (bear in mind sand production problems)** • Exclusive sand control • Sand management (passive)
Step 13	**Select option of sand management strategy based on** • Sand risk /reservoir environment • Environmental constraints on sand disposal • Productivity and reservoir economics
Step 14	**Plan reservoir development and management strategy** • Completion design • Perforation strategy • Sand monitoring strategy • Planning surface facilities • Field economics

4.2 Sand Modeling Process

More often the focus is on one aspect of sanding; this has to be viewed as a whole body for effective field management. Figure 4.1 presents the flow of sand modeling process from sand prediction to control or management. The starting point being formation sand prediction process.

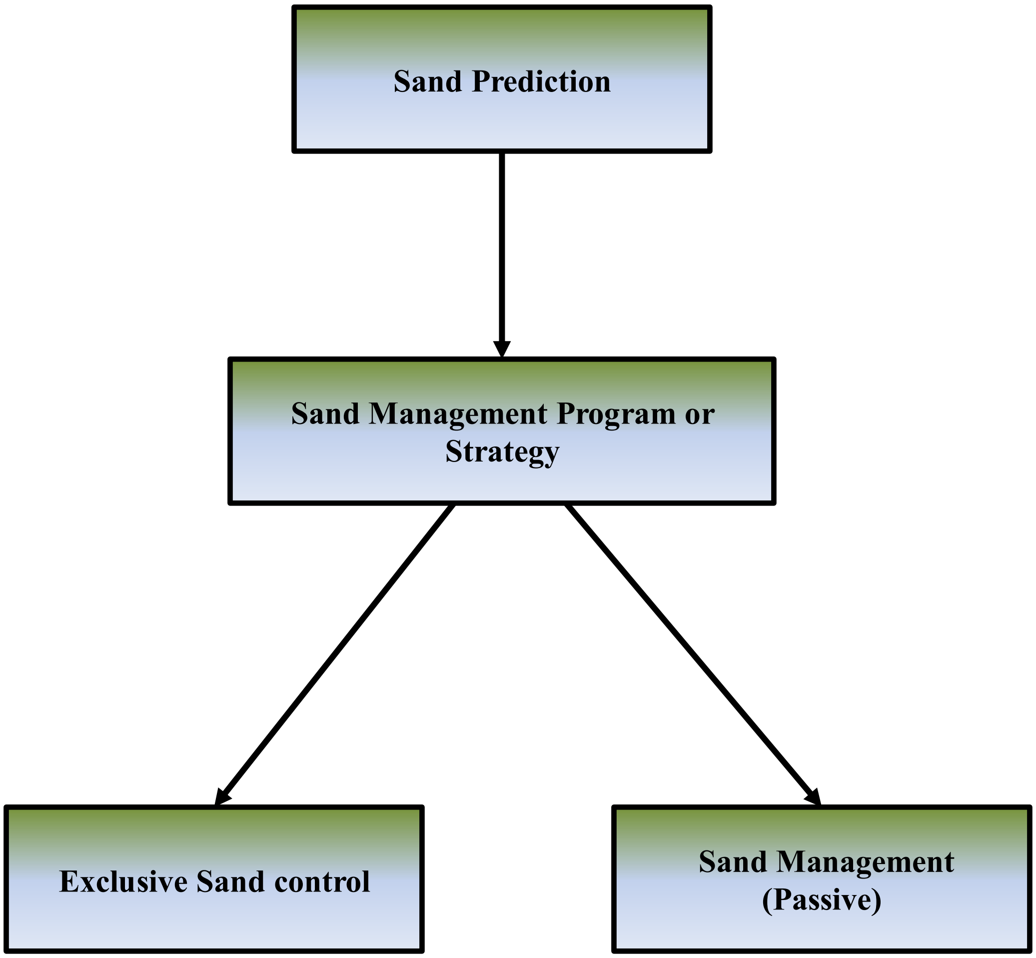


Fig. 4.1 Sand Modeling Process for Reservoir Development

Major reservoir development plan relies on sand prediction in order to effectively execute them. Notable in figure 4.2 are the various aspects of reservoir development strategy connected to formation sand prediction. This embeds in it sand control and management.

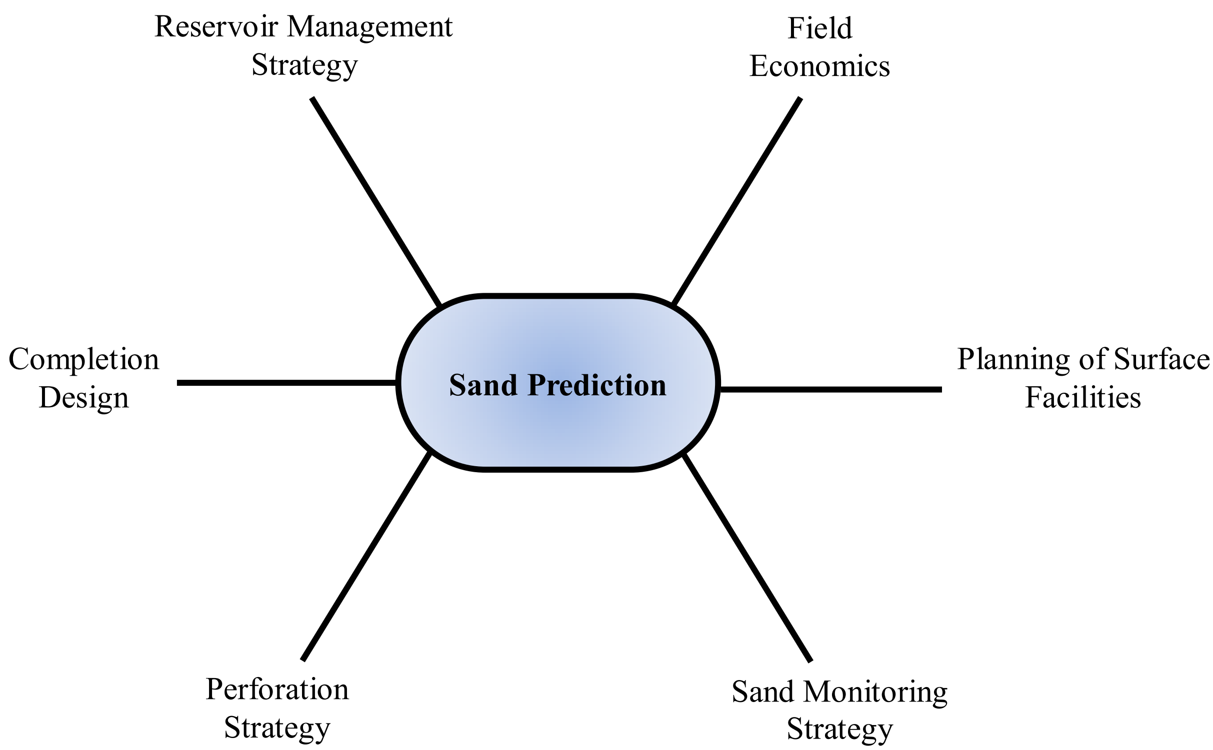


Fig. 4.2: Sand Prediction Applications

Step 12 of the itemized step-by–step sand prediction, control and management mentions risk quantification to determine the choice of sand management strategy to implement. Presented in table 4.4 below is a screening criterion to select likely candidate for sand control. This is based on sand production risk with reference to safety, well economics, environmental constraints etc.

Table 4.4: Screening Criteria to Select Candidate Well for Sand Control

Sand Management Risk / Formation Type/ Well Environment	Very high	High	Medium	Low	Very low
Gas or condensate reservoir	✓	---	---	---	---
High pressure/High temperature reservoirs	---	✓	---	---	---
Solution drive reservoirs	---	---	✓	---	---
Horizontal well	---	---	✓	---	---
Injection well	---	---	✓	---	---
Low productivity index reservoirs	---	---	---	✓	---
Asphalt/ scale precipitation	---	---	---	✓	---
Heavy oil	---	---	---	---	✓

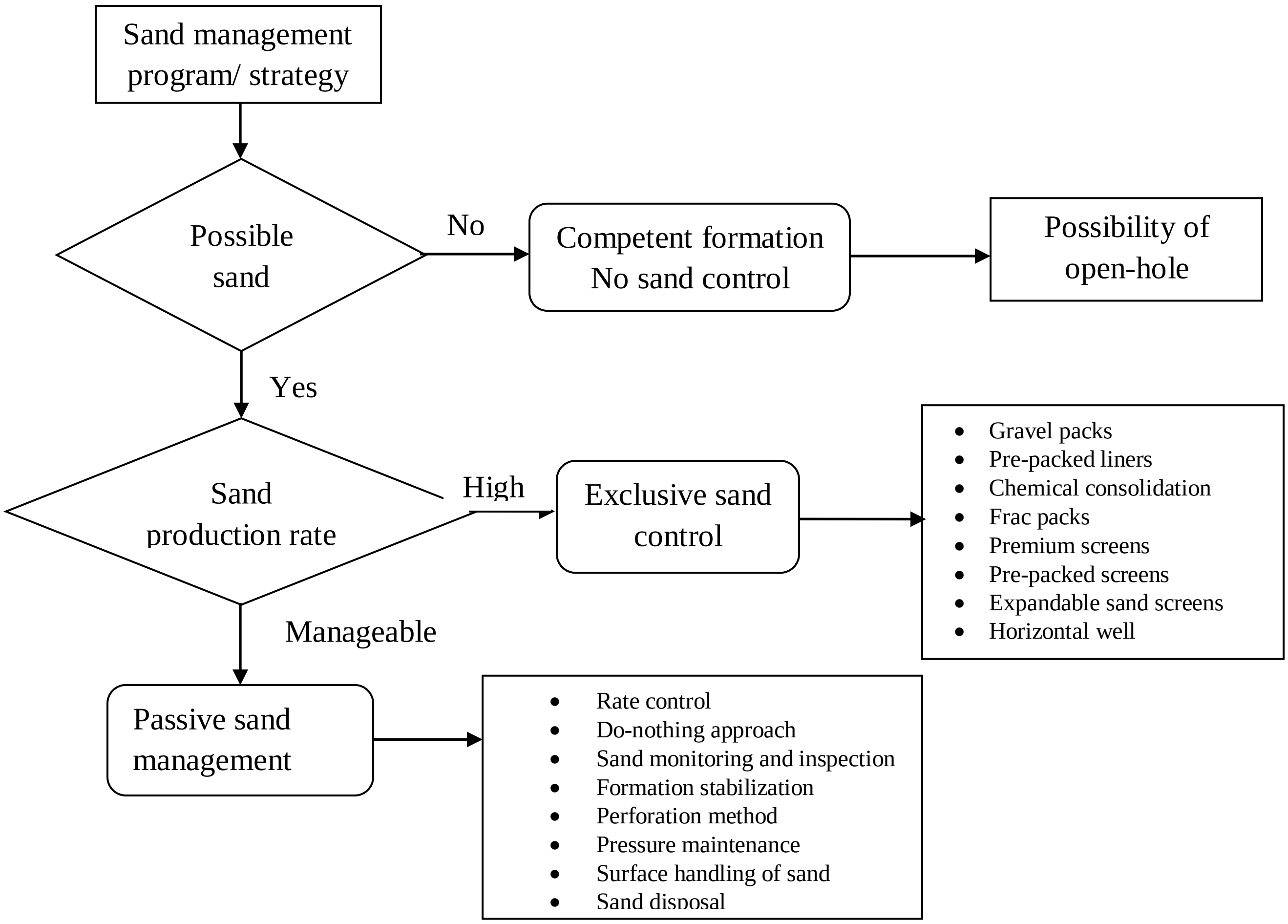


Fig. 4.3: Sand Management Strategy Flow Chart

Fig. 4.3 above describes the flow of events after risk quantification to analysis best fit sand management system. Possible sand control and management that can be used are presented. Together with guidelines presented in chapter 3 to select sand control method to use, table 4.5 below presents different control methods and areas of possible application.

Table 4.5: Guideline for Sand Control Method Selection

Sand Control Type \ Application Area	Highly heterogeneous intervals	Heterogeneous intervals	Horizontal well	Zonal isolation
Standalone screen	Low	Low	High	Medium
Open-hole gravel packs	High	High	Low	Low
Open-hole expandable screens	High	High	Medium	High
Cased hole gravel pack	High	High	Low	Medium
Frac pack	High	High	Medium	Low

Overall sand flow chart for effective sand prediction, control and management is presented in fig. 4.4 below.

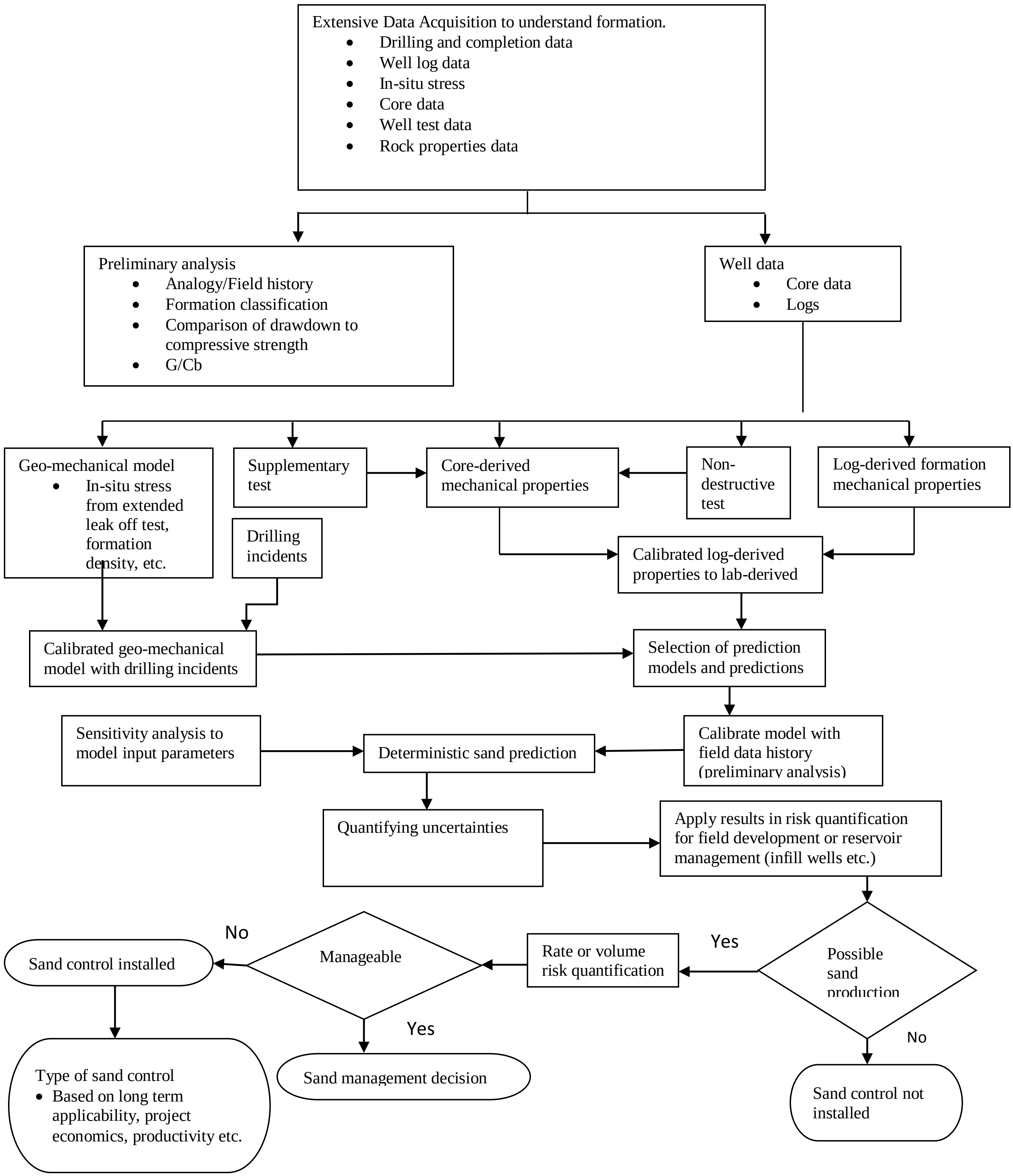


Fig 4.4: Flow Chart for Effective Sand Prediction, Control and Management

CHAPTER 5

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

5.1 Summary

The objectives of this study are as follows: (1) to review state of the art sand prediction, control, and management techniques. (2) to develop effective methodology for sand prediction, control, and management. (3) to develop a step-by-step practical approach to sand prediction, control, and management.

In order to achieve the objectives mentioned above, in chapter two of this study various sand prediction, control, and management techniques were discussed. From chapter two the main types of prediction method are empirical, analytical, numerical and laboratory simulation. These techniques are to be integrated to effectively predict the sanding potential of a formation. Developed effective sand prediction methodologies were presented in chapter three, with emphasis on formation strength identified to be an important parameter in prediction. The decision between sand control (exclusive) and sand management (passive) is identified to be dependent on sand prediction. This makes prediction important in field or well development. Sand control selection methods and sand management methods were also presented in chapter three.

Knowing the sanding potential of a formation helps reservoir management. Chapter four provides step wise procedure to carryout sand prediction, control, and management. Also presented are flowcharts and screening criteria to help select candidate well for sand control. Extensive data acquisition and planning is significant in sand production management. The importance of this is captured in chapters 3 and 4 of this study. Deciding between sand control and management starts with prediction which must be treated carefully as mistakes could cause well loss.

5.2 Conclusions

Based on the theoretical studies and practical observations made from this study, the following deductions and conclusions are made:

1. Integrating sand prediction, control, and management is key for well or reservoir optimization.
2. The integration of sand prediction methods gives a better evaluation of the sanding potential and practical knowledge of the formation sand production behaviour.
3. Sand Management strategy has economic implications through rigorous well and facilities monitoring as well as sand disposal.
4. A step-by-step procedure for effective sand prediction, control and management has been developed.
5. Quantifying uncertainties in sand prediction will further boost the level of confidence in implementing results in reservoir development and sensitivity analysis helps in future studies.

5.3 Recommendations

Based on the scope of this study the following recommendations are proposed:

1. Since formation strength is an important parameter in sand prediction, methods that can measure this parameter in-situ should be developed to aid accuracy.
2. Further work can concentrate on developing a decision tree with economic implications and probabilities of success of the step-by-step procedure given.

NOMENCLATURE

C	Cohesive Strength (psi)
C_b	Bulk Compressibility
CL	Cathode- Luminescence Microscopy
D_{10}	10^{th} Percentile (Sieve Size to Retain 10 % Sand Grains)
D_{50}	Median Percentile Size
DST	Drill Stem Test
E_B	Dynamic Bulk Elastic Modulus (psi)
$E_{dynamic}$	Dynamic Young Modulus
E_S	Dynamic Shear Elastic Modulus (psi)
G	Dynamic Shear Modulus (psi)
h_p	Perforated height in a vertical well
ID	Internal Diameter (in)
L	Horizontal length
OD	Outside Diameter (in)
PDF	Probability Distribution Functions
P_R	Average Reservoir Pressure (psi)
PSD	Particle Size Distribution
P_W	Bottom-Hole Wellbore Flowing Pressure (psi)
SCAL	Special Core Analysis Laboratory
SEM	Scanning Electron Microscopy

TS	Thin Section
TWC	Thick Wall Cylinder Tests
UCS	Unconfined Compressive Strength
$V_{dynamic}$	Poisson's Ratio
V_p	P-Wave (Compressional) Velocity (f/sec)
V_s	S-Wave (Shear) Velocity (f/sec)
XLOT	Extended Leak-Off Tests
XRD	X-Ray Diffraction
P_c	Critical Pressure (psi)
ΔP_{de}	Reservoir Pressure Depletion (psi)
ΔP_{dd}	Drawdown Pressure (psi)
ΔP_{td}	Total Drawdown Pressure (psi)
Δt_c	Compressed Sonic Wave Transit Time (μs/ft)
$\sigma_{1,}\ \sigma_{2,}\ \sigma_3$	Hydrostatic Stresses
$\sigma_{v,w}$	Vertical Effective Stress
σ_{twc}	TWC Collapse Pressure
τ	Shear Strength (psi)
θ	Internal Friction Angle (Degrees)
σ_n	Stress Normal to the Failure Plane (psi)
σ_1	Overburden stress
σ_2	Maximum horizontal stress

σ_3 Minimum horizontal stress

Subscripts

C Critical or Maximum Production Rate Condition above which Sand Production Problems are expected

T Production Test Conditions

Z Conditions of Sand Being Considered

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APPENDIX

Table 1: UCS Models for Sandstones

Model and Reference	Equation	Remarks
Dt-McNally (McNally, 1987)	$C_0 = 185213e^{-0.057Dt}$	Low to medium porosity sandstones, 65< Dt < 100 μs/ft and UCS > 3000 psi, Permo-Triassic age SE Australia
Dt-Mod McNally (Modified McNally)	$C_0 = 838825e^{-0.057Dt}$	A modified McNally equation for unconsolidated and high porosity sandstones with UCS less than 3000 psi
Dt-HRDS (Rahman et al. 2008)	$C_0 = 40847e^{-0.0268Dt}$	Tertiary sandstones,offshore gas field, South Asia
Dt-FORMEL (Raaen et al. 1996)	$C_0 = 145\times(140-2.1Dt+0.0083Dt^2)$	90< Dt < 140 μs/ft
ϕ-FORMEL (Raaen et al. 1996)	$C_0 = 145\times(43-140\phi+63\phi^2)$	0.2< ϕ < 0.35
Dt Cubed-Sand (Chang et al. 2006)	$C_0 = 2.05\times10^9\,Dt^{-3}$	Gulf of Mexico,weak and unconsolidated rocks
Dt-Freyburg (Freyburg, 1972)	$C_0 = 1.55\times10^6 / Dt - 4567.5$	Consolidated Thuringia sandstones, Germany
ϕ-Sarda (Sarda et al. 1993)	$C_o = 16172e^{-11.6\phi}$	Germigny-sous-Coulombs reservoir, with the ϕ < 0.35
ϕ-Vernik (Vernik et al. 1993)	$C_o = 36830\times(1-2.7\phi)^2$	Reasonable for consolidated sandstones with ϕ < 0.30
ϕ-V_{clay}-Vernik	$C_0 = 145\times(254-204\times V_{clay})\times(1-2.7\phi)^2$	Modified Vernik equation with V_{clay} for shaly sandstones with ϕ < 0.30
ϕ-Literature1 (Chang et al. 2006)	$C_0 = 40165e^{-10\phi}$	UCS between 300 and 52000 psi and ϕ less than 0.33
M-Bongkot (McPhee et al. 2000)	$C_0 = 0.0011824M - 1436$	Bongkot Field, Gulf of Thailand, for UCS < 5000 psi
M-Hemlock (Moos et al. 1999)	$C_0 = 1.745\times10^{-3}\,M - 3045$	Cook Inlet, Alaska unconsolidated fine to coarse grained low strength sandstones, 10,000 ft depth
M-GOM (Chang et al. 2006)	$C_0 = 561.15e^{7.862\times10^{-7}M}$	Gulf of Mexico
M-Browse (Chang et al. 2006)	$C_0 = 6104.5e^{1.31\times10^{-7}M}$	Consolidated sandstone with 0.05 < ϕ < 0.12 and UCS>12000 psi, Browse Basin, Australia
E-Plumb (Bradford et al. 1998)	$C_0 = 330.7 + 0.0041E_{sta}$	Worldwide for 725 < UCS < 29000 psi
E-Everest (Bradford et al. 1998)	$C_0 = 330.7 + 1.177\times10^{-14}\,E_{dyn}^{2.7}$	Another form of the E-Plumb equation with dynamic Young's modulus
E-Literature1 (Chang et al. 2006)	$C_0 = 6700e^{1.86\times10^{-7}E}$	Based on static Young's modulus
E_{sta}-C&D (Coates and Denoo, 1981)	$C_0 = 4.54\times10^{-3}\times E_{sta}$	Linear relation between C_0 and E_{sta}
BRUCE (Bruce, 1990)	$C_0 = A\times0.026\times10^{-6}E_{dyn}K_b(0.0045+0.0035V_{clay})$	Applicable to UCS > 4350 psi with $A = 2\times\cos\theta/(1-\sin\theta)$
W&P (Weingarten and Perkins, 1995)	$C_0 = 145\times10^{-12}(114+97V_{clay})K_bE_{dyn}$	unconsolidated sandstones, gas fields in USA
MECHPRO1 (Fjaer et al. 1992)	$C_0 = 8.7\times10^{-12}\,KE_{dyn}(1+0.78V_{clay})$	Sandstones with UCS>4350 psi
MECHPRO2 (Fjaer et al. 1992)	$C_0 = 2.27\times10^{-10}\,M^2\times[(1+v)/(1-v)]^2(1-2v)(1+0.78V_{clay}$	Sandstones with UCS>4350 psi
ϕ-Travis Peak	$C_0 = 4697\phi^{-0.466}$	Tight sandstone with 0.01 < ϕ < 0.18
M-Travis Peak	$C_0 = 3648e^{3.65\times10^{-7}M}$	Tight sandstone with 0.01 < ϕ < 0.18
E-Travis Peak	$C_0 = 3668e^{4.14\times10^{-7}E}$	Tight sandstone with 0.01 < ϕ < 0.18

Table 2: UCS Models for Shales

Model and Reference	Equation	Remarks
Dt- Horsrud (Horsrud, 2001)	$C_0 = 111.65 \times (304.8 / Dt)^{2.93}$	High porosity North Sea Tertiary shales
Dt-GOM (Chang et al. 2006)	$C_0 = 62.35 \times (304.8 / Dt)^{3.2}$	Pliocene and younger shales
Dt-Global (Chang et al. 2006)	$C_0 = 195.75 \times (304.8 / Dt)^{2.6}$	Globally applicable
Dt Cubed-Shale (Chang et al. 2006)	$C_0 = 72.5 \times (304.8 / Dt)^{3}$	Gulf of Mexico
Dt-Lal (Lal, 1999)	$C_0 = 1450 \times (304.8 / Dt - 1)$	High porosity Tertiary shales
E-Horsrud (Horsrud, 2001)	$C_0 = 0.0232E^{0.91}$	High porosity North Sea Tertiary shales
E-Literature1 (Chang et al. 2006)	$C_0 = 0.221E^{0.712}$	Strong and compacted shales
ϕ-L&D (Lashkaripour and Dusseault, 1993)	$C_0 = 145.1\phi^{-1.143}$	Compacted shales ($\phi < 0.10$)
ϕ-Horsrud (Horsrud, 2001)	$C_0 = 424.7\phi^{-0.96}$	High porosity North Sea Tertiary shales
ϕ-Literature1 (Chang et al. 2006)	$C_0 = 41.47\phi^{-1.762}$	Shales with $\phi > 0.27$
Rhob-shale	$C_0 = 0.0123e^{4.89\rho_b}$	Developed from published data for density < 2.4 g/cc

Table 3: UCS Models for Carbonates

Model and Reference	Equation	Remarks
Dt-M&S (Militzer and Stoll, 1973)	$C_0 = (7682/Dt)^{1.82}$	Limestones
Dt-G&R (Golubev and Rabinovich, 1976)	$C_0 = 10^{(2.44+109.14/Dt)}$	Limestones
ϕ-Rzhewski (Chang et al. 2006)	$C_0 = 40020(1-3\phi)^2$	Similar to Vernik formula with different constants
ϕ-Limestone1 (Chang et al. 2006)	$C_0 = 19705.5e^{-4.8\phi}$	Strong limestones with low porosity (0.06 on average)
ϕ-Limestone2 (Chang et al. 2006)	$C_0 = 20851e^{-6.95\phi}$	UCS > 4900 psi in a field in Middle East
E-Limestone (Chang et al. 2006)	$C_0 = 4.66E^{0.51}$	Moderately to very strong limestones (UCS > 2000 psi)
E-Dolomite (Chang et al. 2006)	$C_0 = 64E^{0.34}$	Dolomite with 8700 < UCS < 14500 psi

Table 4: TWC Models

Model and Reference	Equation	Remarks
TWC-UCS	$TWC = 80.8765 \times C_0^{0.58}$	Global for sandstones
TWC-M (Rahman et al. 2008)	$TWC = 10^{-8} M^{1.77}$	Tertiary sandstones, gas field in South Asia
TWC-ϕ	$TWC = 20.62\phi^{-3.54}$	Weak sandstones

Table 5: Friction Angle models

Model and Reference	Equation	Remarks
FANG-Dt (Lal, 1999)	$\theta = \sin^{-1}\left(\left(\frac{304878}{Dt} - 1000\right) / \left(\frac{304878}{Dt} + 1000\right)\right)$	Shales
FANG-M (McPhee et al. 2000)	$\theta = 1.0691 \times 10^{-6} M + 28.51$	Sandstone, Bongkot Field, Gulf of Thailand.
FANG-V_{clay}-1 (Plumb, 1994)	$\theta = 26.5 - 37.4(1-\phi-V_{clay}) + 62.1(1-\phi-V_{clay})^2$	Both sandstones and shales
FANG-V_{clay}-2	$\theta = 20.5 + 15(1-V_{clay})$	Sandstones
FANG-ϕ1 (Weingarten and Perkins, 1995)	$\theta = 57.8 - 105\phi$	Sandstones
FANG-ϕ2 (Perkins and Weingarten,1988)	$\theta = 58 - 135\phi$	Weak sandstones
FANG-ρ_b	$\tan\theta = 0.1\rho_b^{2.85}$	Sandstones