ADVANCES IN SAND PREDICTION AND MANAGEMENT FOR UNCONSOLIDATED RESERVOIRS

BY

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A PROJECT WORK SUBMITTED TO THE DEPARTMENT OF SCIENCE LABORATORY TECHNOLOGY, FACULTY OF LIFE SCIENCE, UNIVERSITY OF BENIN, BENIN CITY EDO STATES, NIGERIA. IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE AWARD OF BACHELOR DEGREE (BSc). IN SCIENCE LABORATORY TECHNOLOGY, DEPARTMENT OF SCIENCE LABORATORY TECHNOLOGY (CHEMICAL/PETROLEUM TECHNIQUES). FACULTY OF LIFE SCIENCES, UNIVERSITY OF BENIN, BENIN CITY.

OCTOBER, 2025.

CERTIFICATION

This is to certify that this project work titled "**ADVANCES IN SAND PREDICTION AND MANAGEMENT FOR UNCONSOLIDATED RESERVOIRS"** was carried out by Praise Imonikhe OREKHA with matriculation number LSC2007344, of the Department of Science Laboratory Technology (Chemical/Petroleum Techniques), Faculty of Life Sciences, University of Benin, Benin City, Edo State, under the supervision of Mr D. A. SALAMI.

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DEDICATION

I wholeheartedly dedicate this work to the Almighty God, whose strength, grace, patience, and provision made the completion of this project possible. I also dedicate it to my parents, in appreciation of their unwavering love, encouragement and support.

ACKNOWLEDGEMENTS

I sincerely appreciate all those who contributed to the successful completion of this research. My deepest gratitude goes to my supervisor, Mr. D. A. Salami, for his unwavering support, guidance, and availability throughout the course of this work. I am also profoundly thankful to my parents Mr Festus Orekha and Mrs Juliet Orekha for their love, encouragement and steadfast support.

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ABSTRACT

Sand production is one of the most troublesome issues in oil and gas development, especially in unconsolidated reservoirs where the formation lacks natural strength. It often leads to equipment wear, production losses, and higher maintenance costs. This study looks at better ways to predict and manage sand production by bringing together different techniques such as geomechanical modeling, log analysis, and real-time monitoring. Traditional control methods like gravel packing, sand screens, and chemical consolidation are compared with more recent innovations such as the Tixier log-based approach and Distributed Temperature Sensing (DTS). Insights drawn from field experiences in Nigerian reservoirs show that when prediction, control and monitoring are combined in a single system, sand problems can be handled more effectively and at a lower cost. Overall, this research highlights that a well-integrated sand management strategy can greatly improve production stability and extend the life of oil wells in challenging reservoir environments.

CHAPTER ONE

INTRODUCTION

1.1 BACKGROUND OF STUDY

Sand production is one of the most persistent challenges in the development and management of unconsolidated reservoirs. It occurs when stresses acting on formation sand grains such as overburden pressure, pore pressure changes, drilling-induced stress, and drag forces from fluid flow cause sand to migrate into the wellbore during production (Oshita *et al.*, 1997; Fortin *et al.*, 2005). Unconsolidated reservoirs, typically geologically young formations with weak or absent natural cementation, are especially vulnerable. In some cases, sand production intensifies in the later stages of reservoir life, as depletion lowers pore pressure and increases intergranular stress (Appah, 2001).

Operational practices further influence sand production. Excessive drawdown and high-velocity fluid flow can dislodge weakly bonded sand grains, transporting them into production streams (Khan *et al.*, 2000; Abubakar *et al.*, 2012). Once initiated, sand production can lead to significant technical and economic consequences. It contributes to equipment erosion reduced productivity, restricted reservoir access, and costly failures of completion and surface facilities (Wang *et al.*, 2000). Since produced sand has no commercial value, its management represents an added cost to operators and a key determinant of reservoir sustainability (Maduabuchi *et al.*, 2017).

Given today's global oil market, sand is regarded as a highly undesirable by-product, with uncontrolled production leading to equipment damage, downtime and losses running into millions of dollars annually (Ikporo *et al*., 2015). Effective sand management therefore remains a top priority for production engineers, combining both prediction and control measures to safeguard operations and optimize economic returns (Mahmud *et al*., 2020).

Traditional sand control technologies have been widely applied to mitigate these challenges. Mechanical methods such as gravel packing, slotted liners and sand screens act as physical barriers to sand influx. Gravel packing, one of the most common techniques, uses specially sized gravel placed around sand screens to filter sand while allowing fluid flow (Khamehchi *et al*., 2015). Similarly, sand screens including wire-wrapped and pre-packed designs, offer enhanced retention capacity. Slotted liners provide another option but may restrict flow due to limited open area (Romanova *et al*., 2015). Chemical sand control, also known as sand consolidation, involves injecting resin systems to bind loose grains while preserving permeability (Abubakar *et al*., 2012). Resin coated gravel techniques further strengthen formation sand and extend wellbore stability (Appah *et al*., 2001). While these traditional methods have proven effective, they often face limitations, including reduced efficiency in reservoirs with complex geology, formation damage during installation and material degradation over time (Wang *et al*., 2025).

Predicting sand production is equally complex. Classic geomechanical models, such as the Mohr–Coulomb and Drucker–Prager approaches, estimate sand failure based on rock strength, in-situ stresses, and drawdown (Coates *et al*., 1981; Antheunis *et al*., 1976). Other models compare flow-induced pressure gradients with the residual strength of disaggregated material (Bratli *et al*., 1981; Perkins *et al*., 1988). Although insightful, these approaches cannot fully capture the coupled effects of reservoir heterogeneity, stress variation and dynamic flow behavior. More advanced frameworks, such as that of the link sand production to shear or tensile failure modes depending on reservoir conditions, yet still face predictive uncertainty in real-field applications (Morita *et al*., 1989). Recent theoretical and experimental studies have shown that cavity size plays a critical role in determining failure mode: large cavities like boreholes typically fail in compression, while smaller ones like perforations may fail in tension or compression depending on material properties and moisture content (Papanastasiou *et al*., 1999). This suggests that prediction methods focusing solely on drawdown or flow rate may oversimplify the problem.

Today, technological advances are reshaping sand prediction and management. High-fidelity geomechanical modeling, real-time downhole monitoring and data-driven predictive analytics provide greater accuracy in anticipating sand onset and optimizing mitigation strategies (Qui *et al*., 2006). Integrated approaches combining traditional methods with advanced monitoring and intelligent control systems are enabling proactive, cost-effective solutions. These innovations not only extend the lifespan of wells but also improve production efficiency and safeguard critical infrastructure.

1.2 AIM AND OBJECTIVES OF THE STUDY

1. Examine advanced methods for predicting, controlling and managing sand production in oil and gas wells.
2. Develop an effective and integrated approach that combines various techniques for accurate sand prediction.
3. Establish a practical, step-by-step procedure for implementing sand prediction, control, and management strategies in reservoir development.
4. Identify key factors such as formation strength, porosity and drawdown pressure that influence sand production and control decisions.

5. Provide guidelines and criteria for selecting appropriate sand control or management methods based on field data, well conditions and economic considerations.

1.3 STATEMENT OF PROBLEM

Sand production is a major challenge in unconsolidated oil reservoirs, causing equipment damage, production delays and costly interventions. The absence of precautionary measures in many wells worsens the problem, leading to uncontrolled sand influx. Although various prediction models and control techniques exist, many fail to accurately forecast sand onset or provide cost-effective solutions under different reservoir conditions. This gap reduces production efficiency and threatens long-term oilfield sustainability.

1.4 RELEVANCE OF THE STUDY

This study is relevant as it explores advanced prediction models, monitoring tools and management strategies aimed at improving the accuracy of sand forecasting and enhancing control measures. The outcomes will guide production engineers and reservoir managers in adopting proactive solutions that extend well life, maintain stable production and ensure the long-term sustainability of oilfield operations.

CHAPTER TWO

LITERATURE REVIEW

2.1 SAND PRODUCTION IN UNCONSOLIDATED RESERVOIRS

The extraction of crude oil from unconsolidated reservoirs is increasingly hindered by the persistent challenge of sand production (Nnurum *et al*., 2024). Sand is produced when the induced in situ stresses are greater than the in-situ strength of the formation (Al-Awad *et al*., 1997). Sand influx occurs when the flow of reservoir fluids surpasses a critical threshold determined by multiple factors, including reservoir completion design, prevailing stress conditions, and the mechanical integrity of the reservoir rock (Osaki *et al*., 2024). The magnitude of sand production can range from negligible quantities measured in grams per cubic meter and posing minimal operational concern to excessive levels that quickly impair injectivity and productivity. Severe cases often result in the plugging of perforations and production liners, reservoir instability, failure of sand control measures, collapse of reservoir sections within weak formations, erosion of pipelines and surface facilities, as well as significant environmental and economic repercussions due to remediation costs (Willson *et al*., 2002).

Sand production in reservoirs is driven by several conditions, such as reservoir pressure depletion, unconsolidated formations, the weakening effect of water on rock strength, drilling-induced disturbances, and cyclic stress variations caused by frequent shut-ins and restarts. High-pressure gradients generated by fluid flow can further aggravate this process by dislodging sand grains from the formation matrix (Osaki *et al*., 2024). Production challenges intensify when induced in-situ stresses exceed the inherent strength of the reservoir rock (Isehunwa *et al*., 2010). A particularly critical factor is the “water hammer” effect, which occurs during unplanned shut-ins or abrupt production fluctuations, often triggered by events such as sudden power outages or rapid declines in productivity. These disturbances generate dynamic wave loadings, inducing undrained mechanical responses in the formation and significantly increasing the likelihood of sand detachment (Jafar *et al*., 2016; Luo *et al*., 2023).

The consequences of sand production in hydrocarbon reservoirs are far-reaching. While in some reservoirs the phenomenon is limited to minor levels, in others it may escalate to catastrophic proportions, completely blocking production tubing and severely reducing reservoir output (Isehunwa *et al*., 2010). The abrasive nature of sand accelerates wear and tear on both subsurface and surface equipment, including subsea systems, pipelines, and reservoir completions, ultimately leading to mechanical failure and increased maintenance requirements (Ranjith *et al*., 2013). Such deterioration not only compromises the structural integrity of reservoirs but also imposes substantial financial burdens due to rising operating costs and diminished hydrocarbon recovery. In extreme cases, uncontrolled sand influx can cause reservoir collapse, posing severe operational, safety and economic risks (Odigie *et al*., 2012). As the costs of sand control continue to escalate, effective prediction and management of sand production remain a critical priority for the sustainability of oilfield operations.

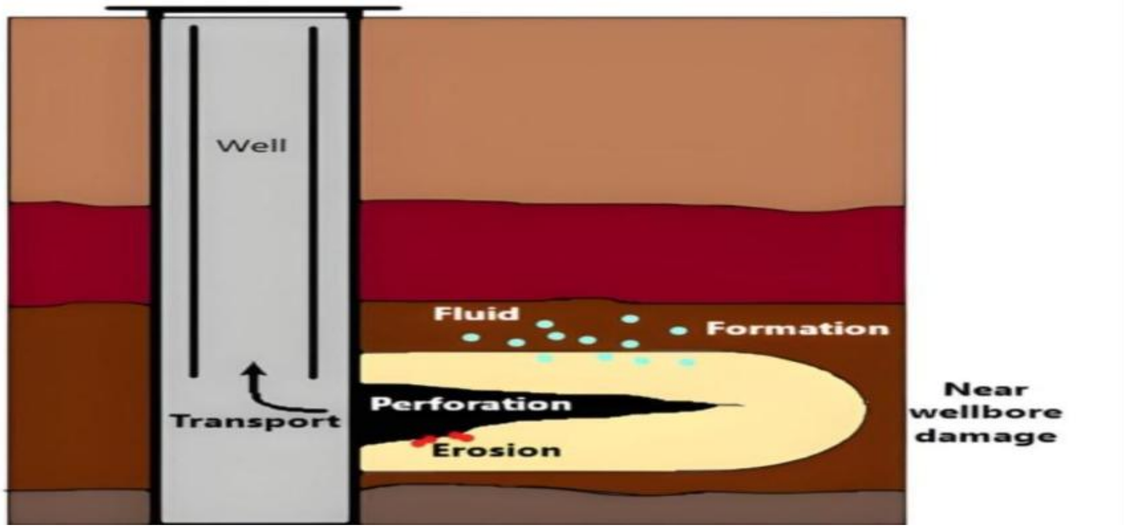


Figure 1: Sand Production (sanding) mechanisms modified (Mahmud *et al*., 2020)

2.2 MECHANISMS OF SAND PRODUCTION

Sand production during hydrocarbon extraction primarily occurs due to mechanical failure of the reservoir rock induced by stress redistribution and fluid flow. The failure of the rock structure allows sand grains to detach and migrate with the reservoir fluids, resulting in operational and structural challenges (Al-Awad, 2001). The primary mechanisms involved include shear or compressional failure, tensile failure and pore collapse.

2.2.1 Shear or Compressional Failure

During production, the induced shear failure surfaces are mobilized and sand debris is generated due to drag forces exerted by reservoir fluid flow. These drag forces dislodge grains from the formation matrix, leading to their transport along with produced fluids into the wellbore (Al-Awad et al., 1997; Al-Awad, 1997). This phenomenon is common in weak and unconsolidated sandstone formations, where the drag forces exceed the inherent cohesion of the rock, weakening its structural integrity. As sand grains detach and move, they can form sand arches that further contribute to instability (Al-Awad et al., 1999; Oshita et al., 1997).

In subsurface conditions, several factors control whether a reservoir will experience mechanical failure. These include (i) the rock's strength (unconfined compressive strength, UCS), (ii) mean-effective stress acting on the formation, and (iii) near-wellbore stress distribution and drawdown caused by drilling and production flow rates (Fitzgrald *et al.*, 1966; Desroches *et al.*, 1998). To predict the onset of failure, the Mohr-Coulomb failure criterion is commonly applied, considering effective principal stresses, pore pressure, cohesion and internal friction angle of the rock. Failure may manifest as shear or compressional failure, particularly when there is significant stress anisotropy between maximum and minimum principal stresses, which amplifies excessive shear stress (Subbiah *et al.*, 2021).

2.2.2 Tensile Failure

Another mechanism contributing to sand production in weak formations is tensile failure. Although relatively rare in most oilfields, tensile failure typically occurs under conditions of high flow rates, which are a function of significant drawdown near the wellbore. This mode of failure usually produces lower volumes of sand compared to shear failure and tends to stabilize over time once the rock has adjusted to stress redistribution (Subbiah *et al.*, 2021).

2.2.3 Pore Collapse Mechanism

Pore collapse is predominantly observed in high-porosity formations such as sandstone and chalk, where excessive hydrostatic stress acts on the granular structure of the rock. This phenomenon leads to the compaction of grains and a reduction in porosity due to localized shear forces acting through grain-to-grain contacts (Fjaer *et al.*, 2008). As stress continues to increase, loosened or broken grains may be displaced into adjacent pore spaces, initiating structural failure. Laboratory investigations indicate that sand grains subjected to these stresses can disaggregate under unpredictable conditions, primarily due to variations in rock type and heterogeneity (Nicholson *et al*., 1998).

2.3 SAND PREDICTION MODELS

Sand prediction models are essential for estimating the onset and severity of sand production in unconsolidated reservoirs. Predicting and quantifying the volume of sand that may be produced in relatively weak sandstone reservoirs is crucial for minimizing risks during the selection of appropriate downhole completion strategies. In several moderately weak reservoirs, screenless completion techniques often offer an effective solution (Acock *et al*., 2003).

Over time, these models have evolved from simple analytical techniques to advanced numerical simulations, improving accuracy and reliability. The models are generally classified into traditional models, which include analytical and semi-analytical approaches, and **a**dvanced models, which incorporate erosion-based methods and numerical simulations.

2.3.1 Traditional Sand Prediction Models

a) Analytical Models

Analytical models have been widely used since the 1970s (Hall *et al.*, 1970; Risnes *et al*., 1982). These models typically assume homogeneity, linear elasticity and isotropy of the formation rock. They predict sanding onset based on stress distribution around perforation tunnels and apply failure criteria such as the Mohr–Coulomb criterion to estimate conditions that lead to rock failure. The Mohr–Coulomb model defines failure as a function of shear stress, normal stress, cohesion, and internal friction angle.

For example, early analytical approaches used the Mohr–Coulomb failure envelope to predict failure initiation in perforated tunnels (Risnes *et al*., 1982). Nordgren improved this by introducing an elasto-plastic formulation with a parabolic yield function to account for plastic deformation, particularly under high effective stresses during reservoir depletion (Nordgren, 1977). Later developments incorporated stress distribution from the wellbore deep into the formation to account for plastic zones (Risnes *et al*., 1982). These studies indicated that in loosely consolidated reservoirs, a plastic zone can extend up to 1meter into the formation, increasing the risk of collapse in uncased wells.

b) Semi-Analytical Models

Semi-analytical models expanded on analytical methods by estimating not only the onset but also the severity of sand production. For instance, early work applied the concept of arch stability to model sand failure mechanisms, validated through laboratory tests (Risnes *et al*., 1982). These models considered overburden stress as the primary factor but often neglected lateral tectonic stresses, limiting accuracy. Later improvements incorporated both shear and tensile failure modes and introduced mass-balance relationships between the yielding zone and cumulative sand production (Geilikman *et al*., 1994). Yield functions such as the Drucker–Prager criterion were used to account for porosity hardening and dilation effects, making these models more robust.

However, these models still faced limitations due to simplified geometry assumptions, such as hemispherical flow patterns around perforations, which may not represent actual cylindrical flow geometries. Studies later confirmed that stress concentrations at perforation tips significantly influence sanding risk, making geometry considerations critical (Weingarten *et al*., 1995).

2.3.2 Advanced Sand Prediction Models

As the complexity of reservoir conditions became more apparent, advanced models emerged to address the shortcomings of traditional method, these include erosion-based models and numerical simulations.

a) **Erosion Models**

Erosion-based models predict sand production as a result of hydromechanical failure, where seepage forces from fluid flow detach particles from the rock matrix. Sand detachment occurs when the pressure gradient-induced seepage force exceeds intergranular cohesion, causing internal or surface erosion (Vardoulakis *et al*., 1996). These models consider localized grain disintegration, porosity changes, and progressive weakening of the rock matrix. Initial formulations assumed zero cohesion and focused on granular displacement within porous media, linking abrasion processes to porosity evolution and grain-to-grain contact forces. This category of models is essential for understanding continuous sanding during production.

b) **Numerical Models**

Numerical simulation methods have become the most accurate and versatile tools for predicting sand production, overcoming the limitations of analytical assumptions. These methods use constitutive models to capture nonlinear, anisotropic and time-dependent behavior of reservoir rocks under complex loading conditions (Johan *et al*., 1993). Techniques commonly applied include Finite Element Method (FEM), Finite Difference Method (FDM), Boundary Element Method (BEM), Discrete Element Method (DEM), Discontinuous Deformation Analysis (DDA), Bonded Particle Models, Meshless Methods (Panos *et al*., 1992).

Numerical models allow for the integration of fluid-structure interaction, enabling full coupling between rock deformation and multiphase flow. For example, FEM has been widely used to simulate stress and strain evolution around perforation tunnels, assess cavity stability and identify bifurcation points leading to sand production (Panos *et al*., 1992; Johan *et al*., 1993). Recent advancements include 3D FEM models combined with fluid dynamics, enabling the prediction of sanding risk and, in some cases, sand production volume (Giorgio *et al*., 2013).

Further innovations introduced elastoplastic damage models, which incorporate rock damage mechanics into traditional failure criteria like Mohr–Coulomb, allowing for progressive failure analysis during reservoir depletion (Mohamad-Hussein *et al*., 2018). Other cutting-edge techniques include zero-thickness interface elements in FEM simulations to model grain-scale dislocation and heterogeneity, achieving accurate reproduction of laboratory sanding experiments (Daniel *et al*., 2020).

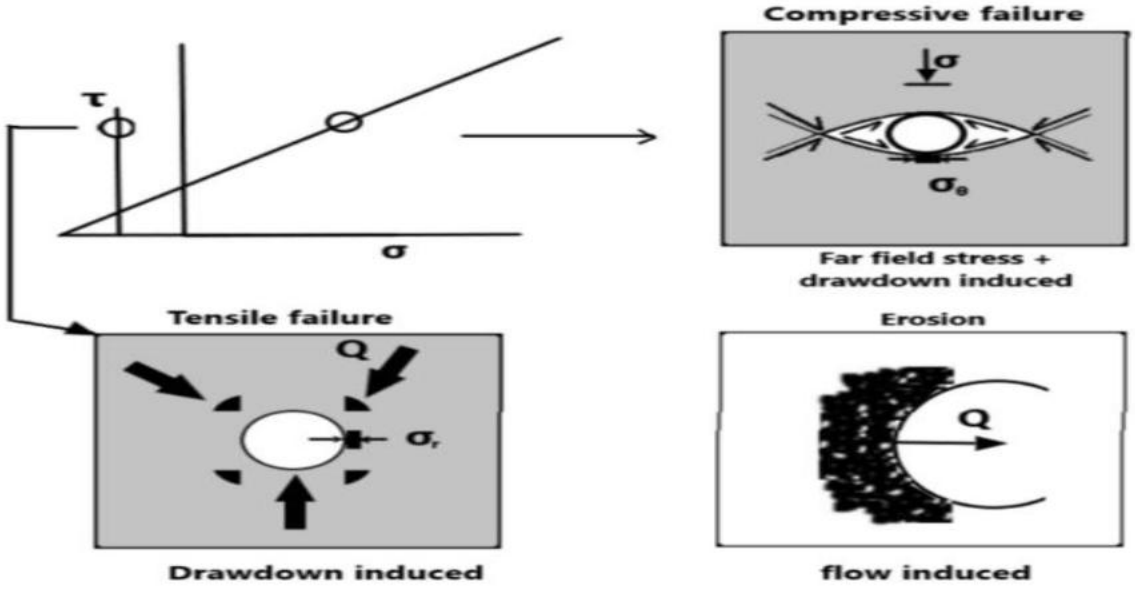


Figure 2: Sand failure mechanisms adapted (Asfha *et al*., 2024)

2.4 MECHANICAL SAND CONTROL METHODS

2.4.1 Conventional Methods

- **Gravel Packs**

Gravel packing remains one of the most widely implemented sand control methods, particularly suitable for unconsolidated and poorly consolidated formations (Khamehchi *et al*., 2015). The technique involves placing gravel of specific size around a sand screen to act as a filter that blocks formation sand while allowing reservoir fluids to pass through (Risnes *et al*., 1982). Properly designed gravel packs enhance wellbore stability, extend completion life, and maintain productivity when implemented with the right equipment under field-specific conditions (Wu *et al*., 2010).

There are two primary configurations:

- **Open-hole gravel packs**, where gravel is pumped into the annular space around the screen to provide borehole support and prevent sand ingress.
- **Cased-hole gravel packs**, which employ a similar concept but are placed through perforations in the casing (Maduabuchi *et al*., 2017).

- **Slotted Liners**

Slotted liners are one of the oldest sand control solutions in the petroleum industry. They consist of steel pipes with narrow, parallel slots cut through the metal. The slots are kept as small as mechanically feasible to maximize sand retention while allowing hydrocarbon flow (Bennion *et al*., 2009). Typically, only 2–3% of the pipe's surface area is open for inflow, which can result in non-ideal radial flow and uneven axial distribution (Romanova *et al*., 2015). Despite these limitations, slotted liners are still widely used due to their simplicity, cost-effectiveness, and durability (Khamehchi *et al*., 2015).

- **Sand Screens**

  Sand screens are designed to prevent formation sand from entering the production stream while maintaining adequate fluid flow (Changyin *et al*., 2017). Common screen types include:

  - **Wire-wrapped screens**, where a triangular-shaped wire is wound around a base pipe, leaving uniform gaps for filtration and spot-welded to vertical supports for stability.
  - **Pre-packed screens**, consisting of two concentric screens with a resin-coated gravel layer sandwiched between them. This gravel ring is hardened to provide extra strength and filtration capacity (Khamehchi *et al*., 2015).

- Chemical Sand Control (Sand Consolidation)

Chemical sand control involves injecting resin-based chemicals such as phenolic, furan, or epoxy into the formation to bond sand grains together and reduce sand migration while preserving permeability (Abubakar *et al*., 2012). Successful treatment requires uniform resin placement across all perforations, long-term consolidation strength and maintenance of post-treatment permeability (Appah *et al*., 2001).

The process generally includes:

- Resin injection via a carrier fluid.
- Separation and deposition of resin around grain contacts.
- Curing under controlled conditions.

Epoxy and furan methods often utilize resin-coated gravel slurries, which are pumped into the well and allowed to cure before drilling out for production. Phenolic resins, partially polymerized during handling, complete curing at temperatures above 57°C (Schwartz, 1969).

Gravel pack design also requires precise analysis of formation properties, gravel-to-sand ratios, slot velocity, and appropriate fluid selection to ensure effective bridging and long-term reliability (Sage *et al.*, 1941).

2.4.2 Emerging Sand Control Technologies

- **Autonomous Inflow Control Devices (AICDs)**

  AICDs are advanced completion technologies designed to regulate fluid flow within the reservoir while minimizing sand production and unwanted water influx, making them cost-effective solutions for sand management (Muhammad *et al.*, 2025). These devices enable uniform fluid distribution based on local water influx levels, thereby enhancing production efficiency.

  Laboratory studies (Kumar *et al.*, 2020) demonstrate AICDs' operational benefits, including reduced rig time and improved flow control during well completion. New designs, such as Rf-PackerSure, integrate multi-path channels, bypass pipes and advanced sand control mesh to optimize gravel placement, even in challenging horizontal and deepwater wells (Tan *et al.*, 2022; Muhammad *et al.*, 2025).

- **Nanoparticle-Based Sand Control**

  Nanotechnology has introduced a promising approach to sand control by incorporating nanoparticles such as SiO_2, TiO_2, and ZrO_2 into treatment fluids. These nanoparticles enhance the mechanical and thermal performance of sand control systems under harsh reservoir conditions (Akhter *et al.*, 2022). Silica nanoparticles, due to their hydrophilic nature and stability, improve the compressive strength of sandpacks sometimes by nearly tenfold while reducing sand production by over 80% (Saghandal *et al.*, 2023).

Their effectiveness depends on parameters such as salinity, pH, and surface charge. By neutralizing surface charges, nanoparticles reduce sand grain mobility and improve consolidation (Kataya *et al*., 2022). When integrated with enhanced oil recovery techniques like smart water flooding, nanoparticle applications can simultaneously mitigate sanding and improve oil recovery (Bahri *et al*., 2021).

2.5 TRADITIONAL SAND PRODUCTION MONITORING METHODS

The oil and gas industry has shown significant concern regarding traditional sand production monitoring methods due to the potential for mechanical equipment wear, safety risks, and adverse impacts on hydrocarbon production rates (Aminu *et al*., 2019). Effective sand monitoring is crucial for reducing operational risks and costs while ensuring sustainable hydrocarbon production.

One conventional technique for sand detection involves analyzing vibration responses to weak shocks. This method monitors the characteristics of fluid flow carrying sand particles that strike the pipe wall, generating specific vibration patterns. By examining these vibration signals, operators can identify and track sand production in offshore oil wells (Li *et al*., 2021). In Bohai Bay, for instance, a vibration-based monitoring approach using a specialized broadband sensor successfully demonstrated the feasibility of real-time sand monitoring (Wang *et al*., 2015).

2.5.1 Surface Acoustic Sand Detectors (ASD)

Acoustic sand detection is another widely used traditional technique. When particles impact the interior of a pipe bend, the resulting acoustic energy can be captured by detectors mounted externally on the pipe (Haugsdal, 2017). During such collisions, a portion of the moving particle's kinetic energy is converted into thermal energy, while another portion becomes acoustic energy (Foster *et al*., 1979). This principle forms the basis for commercially available acoustic sand monitors, which are clamped onto the pipe wall to detect sounds generated by sand particles striking the pipe surface (McLaury *et al.*, 2017).

Sand detectors serve as essential tools for determining the amount of sand present in a flowing stream at specific locations. These detectors can be classified as intrusive or non-intrusive. The non-intrusive type detects sand by "listening" for impact noise on the pipeline, whereas intrusive detectors measure erosion on a probe inserted into the flow stream (Allahar, 2003).

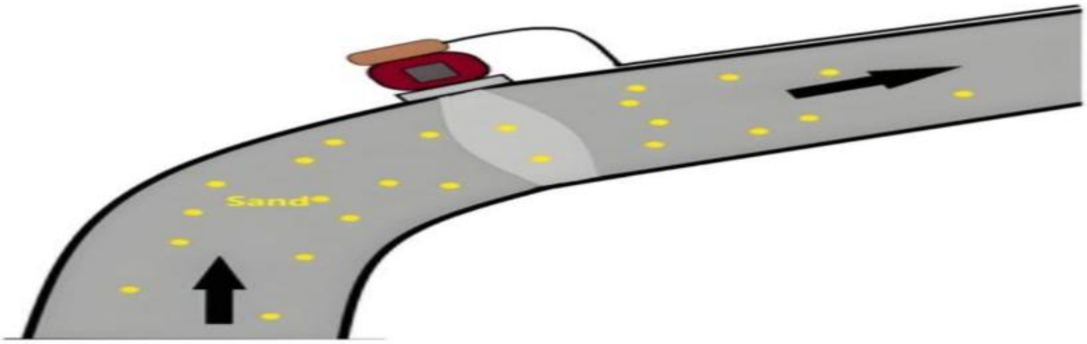


Figure 3: Non-intrusive acoustics probe (Allahar, 2003)

2.6 RECOMMENDATIONS FOR SAND PRODUCTION MONITORING METHODS

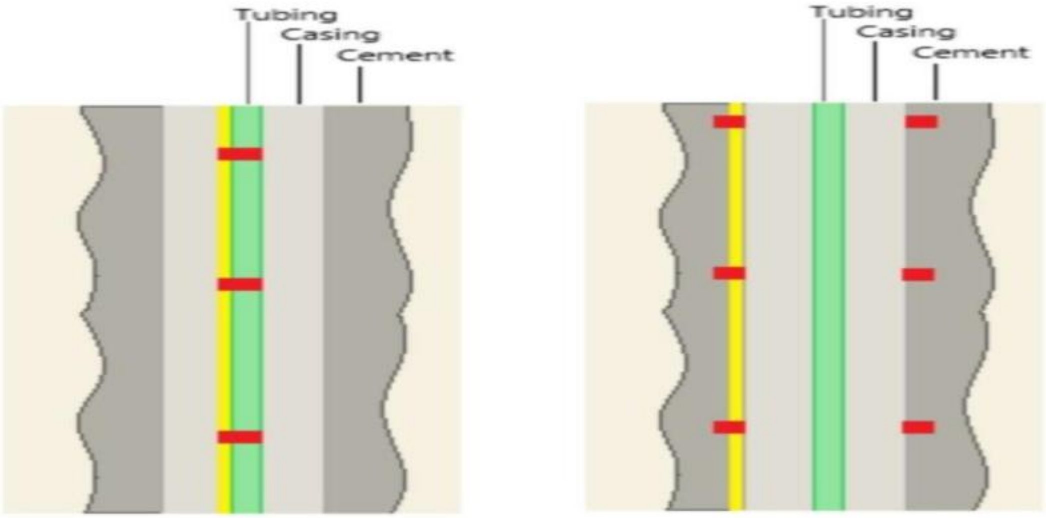
Real-time and precise detection, along with the quantification of sand production, is critical for maintaining well-integrity and optimizing hydrocarbon production. Advanced monitoring techniques, including Distributed Acoustic Sensing (DAS), Distributed Temperature Sensing

(DTS), and Machine Learning (ML), have shown significant potential in revolutionizing sand production monitoring (Ye *et al*., 2014; Gardner *et al*., 2015; Harris 2017).

2.6.1 DAS and DTS Technologies for Sand Production Monitoring

DAS is a fiber optic (FO)-based technology that records sound and vibration signals along an FO cable, utilizing Rayleigh scattering of laser pulses (Harris 2017; Kuvshinov 2016). It can capture dense seismic data over tens of kilometers with high spatial and temporal resolution, making it ideal for continuous, real-time measurements (Lellouch *et al*., 2021; Li *et al*., 2022). DAS systems employ various sensing principles, such as interference sensing, optical backscattering, and optical nonlinear parameter detection, to detect external acoustic or vibration signals in real time (Wang *et al*., 2019). Initially developed for structural health monitoring in civil infrastructure (Ye *et al*., 2014), DAS is now widely applied in oil and gas operations for monitoring wellbore conditions and sand production (Gardner *et al*., 2015).

Similarly, DTS technology provides continuous temperature profiling along the entire wellbore. By monitoring temperature variations, DTS can detect sand ingress, as sand particles typically create a cooling effect when mixed with production fluids (Williams *et al*., 2000). This enables early diagnosis of sand-related issues and prevents damage to downhole and subsea equipment. Furthermore, DTS can be integrated with pressure sensors to enhance the understanding of well dynamics, allowing for comprehensive, real-time sand monitoring without interrupting production (Brown *et al*., 2005).



a) b)

Figure 4: a) Outside Tubing b) Ouside Casing. Different types of DAS installation. Elements of the well are marked, and the fiber is yellow (Lellouch *et al*., 2021).

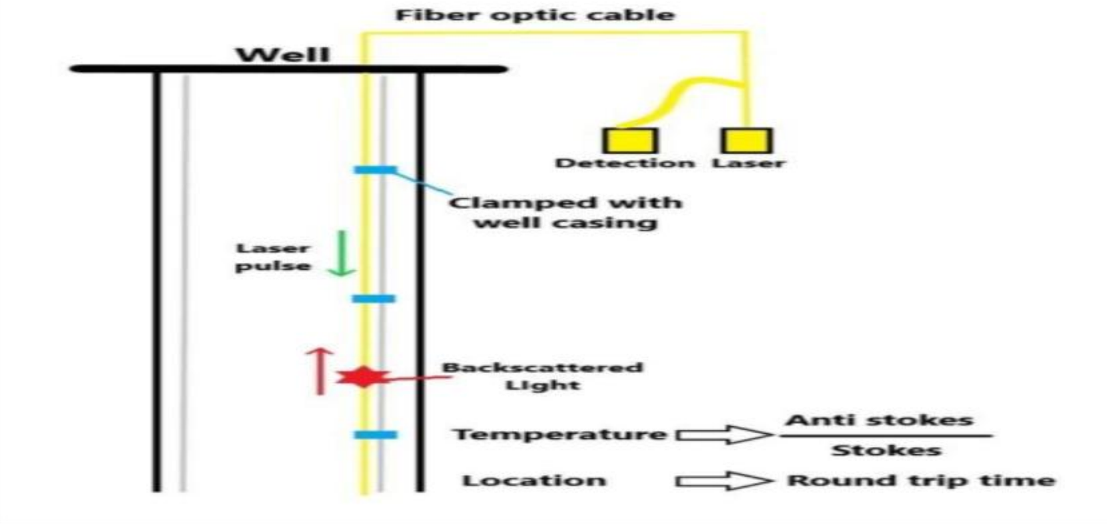


Figure 5: The principles of DTS in well applications (Asfha *et al*., 2024)

2.6.2 Machine Learning Techniques for Sand Production Monitoring

Machine Learning (ML), a branch of artificial intelligence, develops algorithms that learn from data to improve predictive capabilities without explicit programming (Asfha *et al*., 2024). ML has emerged as a cost-effective alternative to traditional sand monitoring methods by leveraging big data and advanced algorithms. These models analyze sensor data, identify sand production patterns, and forecast future trends (Abdelghany *et al.*, 2023). Both supervised and unsupervised learning approaches have been employed for geomechanical characterization and sand management. By processing data from borehole images and multi-arm calipers, ML-based systems optimize sand control strategies and predict critical well conditions.

To ensure effective mitigation and early detection of subsurface movements, real-time monitoring of sand control completions is essential (Earles *et al.*, 2010). Fiber optic support devices and optical wet connections have been designed to monitor strain and temperature on sand screen products, enabling continuous evaluation of mitigation measures and early identification of sand production (Earles *et al.*, 2010).

2.7 LIMITATIONS

2.7.1 Limitations of DAS

The Distributed Acoustic Sensing (DAS) method for sand detection faces certain drawbacks, particularly regarding sensitivity to external noise. Since DAS relies on detecting acoustic waves, it is highly susceptible to interference from environmental noise sources, which can compromise the accuracy of sand concentration measurements, especially in high-noise environments or areas with significant acoustic disturbances. Furthermore, variations in sand particle size and composition can influence the acoustic signals generated during impact, making it more challenging to accurately quantify sand concentration using this approach (Asfha *et al.*, 2024).

2.7.2 Limitations of ASD

Acoustic Sand Detectors (ASD) are widely used to identify sand in oil and gas production wells, playing a vital role in preventing equipment damage and maintaining operational continuity. However, these systems are not without limitations. Most conventional ASDs employ stationary acoustic sensors mounted on the surface of production flowlines, which restricts their ability to pinpoint the exact location where sand enters the system. Additionally, these sensors provide delayed information because of their surface-based installation. Another significant challenge is the difficulty in differentiating genuine sand signals from false alarms due to calibration limitations, which can affect the reliability of results (Khan *et al*., 2015).

2.7.3 Challenges in Data Analysis and Interpretation

Fiber Optic (FO) technology, including DAS and Distributed Temperature Sensing (DTS), generates a large volume of continuous data along the entire wellbore, unlike conventional point-based measurements. While this provides extensive monitoring capabilities, it also presents significant challenges in data analysis and interpretation. The vast data sets require advanced analytical models and sophisticated interpretation techniques to extract meaningful insights (Asfha *et al*., 2024).

2.7.4 Reliability and Environmental Sensitivity

Although DAS offers several advantages in geophysical monitoring, it suffers from a lower signal-to-noise ratio (SNR) compared to traditional geophone systems. Extraneous noise from downhole activities such as pumping operations, fluid flow, and even natural earth tides can mask the weak acoustic signals associated with sand production, thereby reducing detection accuracy (Asfha *et al*., 2024) Moreover, FO cables and sensors are sensitive to environmental conditions such as temperature changes, humidity, and mechanical vibrations. These factors can cause fiber expansion or contraction, resulting in signal attenuation or misalignment. In severe cases, environmental stress can physically damage FO sensors, making them unreliable for long-term monitoring (Maier *et al*., 2023).

From the reviewed literature, it is evident that while significant advancements have been made in predicting and managing sand production globally, limited studies have focused on the unique challenges of unconsolidated formations typical of Nigerian reservoirs. Factors such as sand retention efficiency, installation risk and completion type remain context-dependent, varying across field conditions. Therefore, Chapter Three focuses on evaluating the practical application of these sand control principles within unconsolidated reservoirs, using field experiences and guidelines developed from the Nigerian oil industry as reference points.

CHAPTER 3

EFFECTIVE METHODOLOGY FOR SAND PREDICTION, CONTROL AND MANAGEMENT

3.1 INTRODUCTION

A common issue in most fields that produce from unconsolidated reservoirs is the creation of sand. Other variables have been shown to be involved, in addition to the inherent tendency of these formations to create sand because of reduced compaction. These include the amount of loading and unloading, water breakthrough and pressure depletion. The combination of sand prediction, control, and management is necessary to address the issue of sand production; this requires a paradigm change away from only examining a portion. Using best field practices, this ultimately entails the collaboration of the reservoir, production, completion and drilling engineers. It is crucial to make accurate sand predictions since they serve as the foundation for good optimisation in terms of total cost and productivity. Comparable to a decision-making tool, sand prediction guides the selection between sand management (passive) and sand control (exclusive). The decision about sand management is based on the tolerance risk of sand production in a certain reservoir. Compared to unconsolidated formations, which experience sand production early in their productive lives, consolidated and friable reservoirs experience sand production later. Thus, prior to installing or putting into practice a sand control or management approach, it is important to comprehend the formation's properties. The new approach to reducing sand output is centred on employing drilling operations, comparing the various forecast approaches and using precise data with little uncertainty.

3.2 SAND PREDICTION METHODOLOGIES

The topic of whether the formation will generate sand, the rate or amount of sand production, and the expected timing of sand production should all be addressed by a formation sand prediction research. Answers should be provided for at least two of these questions, if not all of them. An effective forecast is produced by combining the several sand prediction strategies. Consequently, the following techniques are provided in order to accurately forecast sand production:

The process that produces sand: Understanding the processes that produce sand is crucial, particularly how one might become more dominant in a formation. These will aid in the forecast process. For instance, there is a greater chance that water inflow will start the creation of sand if the reservoir has a high oil-water contact (i.e., near the surface or payzone). Table 2.1 lists and discusses a number of elements thought to affect sand output. Formation, completion, and production are the three categories into which the factors are divided. These include, to name a few, rock strength, flow rate, pressure drawdown, permeability and reservoir depth. However, because of the lack of data at the time of field formation, it is not feasible to incorporate all of these into a forecast approach. Three elements formation strength, production rate, and in-situ stresses, have been identified as crucial in sand prediction. Modelling the mechanism of formation failure, which is connected to these three characteristics, is part of sand prediction. Chapter 2 discusses the expected failure process, which is mostly determined by the kind of formation (consolidated, friable, or unconsolidated). All of the information pertaining to the formation has now been collected. These include geological data, coring, rock characteristics, logging data, and offset well data (production, drilling, completion, etc.). Information on in-situ field stresses is obtained; The minimum horizontal stress from extended leak-off tests (XLOT), the maximum horizontal stress (σ2) from minimum horizontal stress (σ3) and overburden stress (σ1), or the assumption that they are equal, i.e., σ3 = σ2, overburden stress from formation density evaluation or via simply applying a gradient of 1.12 psi/ft to the depth in question (Craig *et al*., 2007).

The usual formation densities are shown in Table 3.1.

Table 3.1- Typical Formation Densities (Craig et al., 2007)

Material	**Density (glee)**	**Overburden (psi/ft)**
Sandstone	2.323	I.OJ
Shale	2.675	1.16
Limestone	2.611	1.13
Dolomite	2.899	1.26
Halite	2.323	I.OJ
Granite	2.691	1.17
Average	**2.587**	**1.12**

Formation classification: The first step in predicting the formation sand should be to determine the kind of formation in which the reservoir is located. These aid in determining whether the reservoir is consolidated or unconsolidated. Typical sand-producing formations were presented by Morita et al. (1991). The data they offered may be used to classify formations for prediction purposes and aid in understanding various formation behaviours with regard to sand generation. Firsthand knowledge that the formation is likely to generate sand is obtained since it is well known that sand production is unique to unconsolidated reservoirs. Acoustic or sonic sand log travel time (Δt) can be used to identify this. The level of consolidation is indicated by adjacent shale barriers to sandstone. When the sonic or acoustic log travel time (Δt) in the shales is less than or equal to 100 μs/ft, it indicates that the sand is firmly compacted and consolidated.

The travel time (Δt) in unconsolidated sands is more than 100 μs/ft. Veeken et al. (1991) defined a range of 90 to 120 μs/ft below which sand management is not necessary (sand does not exist).

This differs depending on the geography or field.

Porosity: Porosity is a formation feature that may be predicted. The majority of unconsolidated formations with porosity between 30 and 34% have a high likelihood of generating sand. Cores and well logs can be used to measure porosity. Sand control is not required in rocks with lower porosity.

Analogy technique and/or field history: The analogy method is used in green fields, and field history and analogies can be used to inform the drilling of a new well in an established field. This is due to the fact that there are already wells in the field; the new well gains knowledge from these wells. This approach offers first-hand knowledge that helps predict what the reservoir will produce. The reservoir's sanding potential is predicted using offset well data from other wells in the same horizon, field, or depositional environment. It is helpful to draw conclusions, particularly from the production data and completion type utilised in these kinds of settings. For this method to work, all wells must have comparable fluid types, rock characteristics, flow rates, and pressure drawdown. This comparison is based on previously collected data.

DST, or Drill Stem Test: Individual well testing by DST is required for this. To ascertain the reservoir's sanding potential, it is flowed under conventional completion. Until sand is generated or a maximum allowable rate at which the reservoir can be produced is determined, the well is flowing through the chokes at gradually increasing flowrates. This allows for the establishment of a sand-free production rate and the making of a sand control completion choice.

Drawdown versus compressive strength comparison: A formation's rock strength indicates how consolidated (hard) it is. The reservoir's compressive strength and pressure drawdown may be connected. Exxon's research indicates that when the drawdown reaches 1.7 times the compressive strength, sand is produced.

Well logs: Because they are created in-situ, they offer a continuous profile of the formation data. In order to determine elastic rock parameters like Poisson, sonic, density, and neutron logs are employed as indicators of porosity and rock strength, which are crucial for prediction.

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;

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

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

The dynamic qualities can be corrected to static properties using a variety of correlations. Because these relationships apply more to certain areas than others, care should be used while applying them. The connections between different authors and the locations that are best suitable for utilisation are clearly listed in Khaksar et al. (2009)'s study (Appendix).

At this point, it is guaranteed that cores are representative, ideally kept, and ready for rock mechanics testing. When sampling for a petrophysical test, core samples should be obtained to prevent utilising cores that are slabbed or degraded, meaning they have many abnormalities. **Technique in the lab:** Sand prediction is a laborious and time-consuming laboratory test method. Because of its dependability, it offers the greatest rock mechanics parameters for prediction. The log-derived strength models are calibrated using them. Chapter 2 has discussed a variety of laboratory examinations. Non-destructive rock strengths can be added to the tri-axial test, which is used to construct the Mohr-Coulomb failure criterion (established rock failure envelope).

Supplementary testing: Tests and procedures carried out on core samples that complement the information on rock strength are known as supplemental testing. This is due to the fact that sandstones can consist of a variety of minerals and rocks, each having a unique strength that can be determined by further testing. Petrographic analyses and the Special Core Analysis Laboratory (SCAL) are the main approaches of these procedures. These ought to be included in a software for testing the rock strength in a lab. They address the subject of why certain phenomena occur during testing and provide further details on the core samples. For instance, the formation may contain pore infilling and grain coating minerals that provide failed zones their arch stabilising action. These assessments 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 1nicroscope)

Losses, breakouts, and blocked pipes are among the drilling occurrences used to validate the geomechanical model for the field. This lowers the uncertainty in the obtained geomechanical parameters.

Choosing a model: The theoretical modelling of perforation and cavity stability serves as the foundation for analytical and theoretical sand prediction techniques. The industry frequently uses simple Mohr-Coulomb, which implies that rock behaves elastically under stress. The Drucker-Prager and Hoek-Brown failure criteria are also applicable. In chapter two, these were covered. Given the constraints imposed by data unavailability, the model type to be employed in prediction (sand production risk quantification) should be chosen based on its best fit for the intended application and acceptable accuracy. Finite element methods are therefore rarely employed as their complexity is not justified by the time, cost, or data requirements. Sand output is frequently linked to safe/critical drawdown rates, flow rates, volume, and time in sand prediction models. The questions of whether and how much should be addressed by the prediction model. After that, conservatism is eliminated by calibrating the model using the field data and offset well records that are currently accessible.

Quantifying uncertainties: this entails calculating the uncertainty of the prediction model's deterministic outcome. As previously mentioned, the model's input data has inherent uncertainty. This simulation may be carried out for the intervals of interest using Monte Carlo using @risk. It is necessary to incorporate accurate Probability Distribution Functions (PDF) of the model input parameters into the simulation. A certain amount of risk certainty is provided by quantifying uncertainties.

Sensitivity analysis is used to ascertain how much each input parameter affects the model's output. This will control how accurately such parameter or parameters are obtained.

3.3 SAND CONTROL SELECTION

The choice of this method depends on the risk involved in sand manufacturing as well as sand forecast. Sand management is necessary since managing the amount of sand generated will not be cost-effective. In unconsolidated reservoirs where sand generation occurs sooner rather than later, this is frequently the last choice. Sand control entails sand consolidation, gravel packing or frac packing the well, and the installation of downhole screens and slotted liners in completion. Chapter 2 detailed these different approaches. The use of sand control is justified by operational risk or the impacts of sand production, as discussed in chapter 2. Long-term sand production prevention, not initial cost or productivity, must be the basis for choosing the first completion. It is important to take into account the total cost of workovers, cleanouts, and other expenses that may arise throughout a productive life. The formation grain size distribution must be understood in order to choose the best screen size or sand control method. The initial finish selected for consolidated reservoirs should allow for the future installation of a sand control system.

The following are some strategies for efficient sand control:

3.3.1 Drilling Practices

Drilling efforts can remove the issue of high drawdown caused by near well bore damage. The issue of uneven sand consolidation and gravel pack placement or needless localised fluid velocities might result from excessive drawdown to satisfy economic or production objectives, as discussed in Chapter 2 (shear and tensile). Non-impairing drilling and completion fluids should thus be utilised to avoid formation damage that may arise during drilling and the productive interval's completion. Drilling fluid that will maintain good hole cleaning and minimal damage to the pay zone should be utilised, as should drilling mud weight that inhibits formation dilatation. In order to select the most appropriate drilling and completion fluids for the formation, information from prediction studies is utilised.

3.3.2 Horizontal Well

As mentioned in chapter 2, one of the causes generating sand generation is reservoir fluid velocity. The movement of reservoir fluid generates the frictional drag force applied to the formation sand grains. The viscosity of the reservoir fluid being created and the fluid flow velocity are closely correlated with this frictional drag force. The mean flow velocities in horizontal wells are lower than those in vertical wells by a factor of hp/L, where hp is the vertical well's perforated height and L is its horizontal length. In an unconsolidated sand reservoir, a horizontal well with a basic perforated liner has been bored and finished. It hasn't produced a noticeable amount of sand at the surface in nearly two years of operation (Igbokoyi, 2011). Reducing the inflow of undesirable reservoir fluid, such as water, which has been identified as one of the elements contributing to the creation of sand, is another crucial use for horizontal wells.

Thus, horizontal well drilling aids in sand management.

3.3.3 Selecting Appropriate Sand Control Method

Formation sand properties often dictate the choice of sand management technology. However, the results of the sand prediction model, field history data, wellbore and completion design, reservoir characteristics, surface facility design, and project economics can all provide the knowledge required to choose a sand control approach. Sand retention potential determined by physical testing is more dependable when choosing the right sand screen suitable for a formation since features like homogeneity and fines content are visible. For this test, core samples from a laboratory test on rock failure can be used. The lowest pressure drop combined with an appropriate degree of sand retention determines which screen should be used. Expected issues from sanding are noteworthy in the choosing of a sand exclusion approach. In addition to the works covered in Chapter 2, Morita et al.'s (1991) work is helpful in this respect. The issues consist of:

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 neighbouring fields and offset wells can be utilised to choose a sand management strategy. Information from a sand prediction model offers insight into the formation features and history of sand production, but evidence from these fields or wells may not be as useful. Using the information so supplied, the best suitable sand control approach may be chosen. These methods may be used in new wells if the field or wells understudied have documented histories of sand output being reduced by sand control measures.

3.3.3.2 Wellbore and Completion Design

The well trajectory, casing size (wellbore) and completion types (open hole or cased hole) may all be used to choose a sand control technique. Because of the high level of compaction, open hole completions are frequently used in consolidated formations. The conventional 41/2 tubing works well for a successful sand exclusion process. Because they disintegrate more quickly, some sand exclusion measures, such as screens, are significantly impacted by hole deviation. Chapter 2 has covered a variety of screens along with their benefits and drawbacks. Along with other sand management methods, the one that works best for a formation might be used.

3.3.3.3 Reservoir Properties

The selection of a sand management method can be influenced by reservoir characteristics such as permeability, sorting, productive interval duration, porosity, sand quality (the presence of undesired shale streaks), reservoir temperature, and reservoir pressure. A certain amount of depth filtering is possible with pre-packed screens, and pressure drops are kept to a minimum by their extremely high permeabilities and comparatively high porosity of over 30%. For longer sand intervals, gravel pack is advised; a gravel pack with a narrow grain size distribution is more effective. With the exception of high temperature and pressure reservoirs where sand control is required, reservoir temperature and pressure impacts do not always influence the choice of sand control technique.

3.3.3.4 Surface Facilities

The choice of a sand control system is frequently influenced by surface sand monitoring devices (twin-pot sand-filtering unit, acoustic sand detectors), erosion-resistant devices (sever-service adjustable choke) and sand disposal. The majority of the materials used in surface facilities should be resistant to erosion, and sand-monitoring equipment should be put in place to keep an eye on the generation of sand. It is important to consider environmental limits that need thoughtful methods of disposing of sand in a way that is environmentally acceptable. Sand disposal may result in increased overhead costs, as discussed in chapter two offshore.

3.3.3.5 Project Economics

When choosing a sand control method, well economics is crucial. Costs associated with initial sand control, completing repair (workovers, etc.) and interrupted production (productivity loss) should all be taken into account. Sand control remediation costs are frequently quite costly, which may have an impact on the project's profitability, particularly in situations when well productivity is low. The availability of rigs or the usage of contemporary methods like coiled tubing, etc., may be the cause of this high expense. The gravel packing alternative seems to be more expensive, requiring more equipment and longer rig time, as demonstrated in the work of Guinot et al. (2009). The tables below provide several sets of recommendations for choosing a form of sand control based on field experience.

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	NIA (4)	Good	NIA
Deviated hole	Good	Good	V.

(1) Longest interval treated to date is 16 feet. With perforation \vashing, zone lengths can be longer but are only lintited by mixing blender capacity.
(2) When isolated and treated separately
(3) May be uneconomical
(4) NIA- not applicable
(5) (5) The n1ajority of the \Veils gravel packed \Vith 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 S	Good	Poor	Fair (b)
hort interval	Good	Good (c)	Good
Permeability variation	Good	Poor	Good
No rig	NIA	Good (c)	NIA
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 \vells has produced little or no sand			

3.4 SAND MANAGEMENT

Sand management means allowing a certain quantity of sand to be produced by the reservoir; in this case, it is acceptable to create certain sand particles using reservoir fluids. Planning the sand life cycle in terms of production rate control, sand inspection and erosion monitoring equipment, reservoir pressure maintenance, well bore cleaning and sand surface management and disposal are all necessary for this. Sand prediction data are used to evaluate risk, which informs sand management decisions. Perforation techniques like orientated perforating depend on precise in-situ stress prediction to ensure that perforating is done correctly. Sand management is used when the amount of sand is controllable. The expense of installing a costly down hole sand control equipment is avoided using a sand management strategy. Optimal flow rates and well productivity have been achieved by its effective application in heavy oil production in Canada. The following are some techniques for managing sand:

- 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

An essential component of sand management is sand monitoring and inspection. Risks to safety, the economy, and the environment make this crucial. For formations without sand control installed, surface checks are crucial for detecting the existence of generated sand and measuring its impact on erosional processes. In situations when the original completion plan has to be revisited, it creates a method for predicting and quantifying sand rate. The makeup of the surface facilities for sand production monitoring and inspection is mostly determined by the kind of well or reservoir. The visual examination approach is frequently used to check the sand. This includes checking for sand accumulation in separators, sand traps, chokes and other surface facilities for erosion. Erosional sand probes, acoustic sand detectors, batch monitoring, and X-ray and ultrasonic surface facility inspection are also used in monitoring.

- Volumetric sand monitoring is done using sand traps. In order to collect sand, sand traps are typically placed near tees and bends. Since the sand volume is determined by dismantling the sand trap after a while, the approach does not give real-time data. Sand traps are often separators. However, this approach is ineffective.
- Choke inspection: this more dependable form of sand monitoring and inspection looks for erosion or the presence of generated sand inside the choke. The consequences of erosion on the choke are visible, and abrupt changes in output rates may also be signs of choke erosion.
- Fluid sampling: collecting reservoir fluid following the use of a primary separator for sand monitoring, which includes centrifugation for sand cuttings and water. This measurement of Bottom Sediment Water (BS&W) is carried out during routine production or appraisal well testing. The method's sensitivity cannot be guaranteed and a lot of sand typically stays in the primary separator (William and Joe, 2003).
- Electronic sand detectors are installed in or on flow lines and offer the ability to measure sand generation in real time. These consist of non-invasive acoustic sand detectors, intrusive acoustic or sonic probes and intrusive erosional probes. Downstream

of the wellhead, intrusive probes are inserted into the flow line. Erosional probes track material loss from sand erosion using the electrical resistance theory. Acoustic probes detect the noise produced by impinging particles on the probe by using the piezoelectric action. The Piezo-electric effect is also used by non-intrusive acoustic sand detectors, which are particularly appealing to subsea projects since they provide the opportunity for Remotely Operated Vehicle intervention to enable service (Navjeet, 2004).

- Although real-time measurements are not possible, X-ray and ultrasonic examinations also track and indirectly measure the amount of sand produced. The X-ray approach provides a two-dimensional image of the whole flow line segment.

3.4.2 Surface Handling of Sand

This is a procedure that permits the production of a measurable amount of sand in addition to reservoir fluids. Because it works well in thick oil deposits, it is mostly utilised there. This necessitates the efficient use of sand handling methods while taking the risk of sand generation into consideration. When using this strategy, the whole cost of well operating and the sand disposal plan, particularly offshore, should be taken into account. In this case, a high-quality formation sand forecast is crucial.

3.4.3 Do-Nothing Approach

When sand output is not a concern, this method works best in cemented formations. This method uses "bare-foot" openhole completions in addition to cased and perforated completions. When rock begins to break, this method can be troublesome, although it minimises the initial finishing cost. In land operations, low-rate shallow wells are often needed for applications of these completions in sand-prone locations. In such circumstances, wells can be bailed and separators cleaned as part of standard field maintenance procedures.

CHAPTER 4

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

RESULTS

4.1 STEP-BY-STEP SAND PREDICTION, CONTROL AND MANAGEMENT PROCESS.

When exploring and evaluating a reservoir, sand concerns should be taken into account in order to pinpoint productive periods that have the capacity to provide sand. The decision to use management or sand control is based on the degree of sanding potential. When making judgements on field growth, the entire idea of sand forecast, control and management must be kept in mind. The entire field or well development plan is impacted by sand prediction, which impacts recovery. Sand prediction is applied as a foundation for significant reservoir development initiatives, as shown in Figure 4.2. The methods discussed in the third chapter are covered in this chapter. In order to guarantee an efficient sand modelling procedure for reservoir development, Table 4.3 outlines fourteen processes.

Table 4.1 Step-by-step Sand Prediction Procedure

Step	**Activity**
Step 1	**Formation evaluation process** Assemble team of key personnel (Completion Engineer, D1illing 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 info1mation Core data
Step 3	**Carryout preliminary analysis on sand prediction using** Analogy /fieJd history Formation classification G/cb
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-destn1ctive test Log: analysis
Step 6	**Calibrate log-derived properties to lab-derived properties using** Appropriate con•elation 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** Forn1ation characteristics Sin1plicity and versatility Time and cost Available data Provide n1eans 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	**Activity**
Step 1	**Assess possible sand production potential of the formation from predictior 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, clear drill pipe or tubing) In consolidation perform (acidizing, preflush and fonnation 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, D1illing 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 info1mation • Core data
Step 3	**Carryout preliminary analysis on sand prediction using** **Analogy /fieJd history** • Formation classification • G/cb • Comparison
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-destn1ctive test Log: analysis
Step 6	**Calibrate log-derived properties to lab-derived properties using** □ Appropriate con•elation 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 (DSl)**
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 Productivitv and reservoir economics
Step 14	**Plan rese1voir development and management strategy** Completion design Petforation strategy Sand monitoring strategy Planning surface facilities Field economics

4.2 SAND MODELING PROCESS

More often than not, just one part of sanding is emphasised; for field management to be efficient, this must be considered as a whole. The progression of the sand modelling process from sand prediction to control or management is shown in Figure 4.1. The formation sand prediction method serves as the foundation.

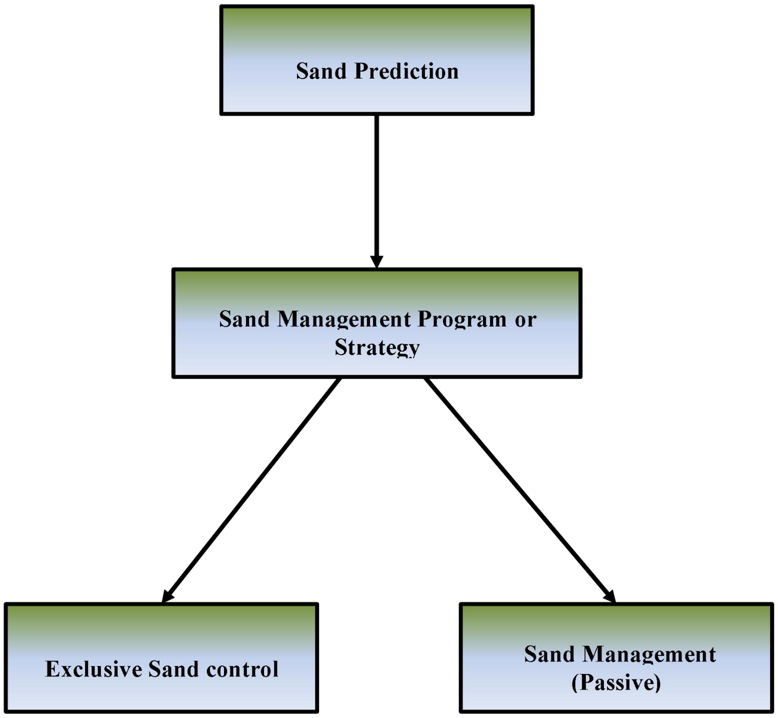


Fig. 4.1 Sand Modeling Process for Reservoir Development

Sand prediction is essential to the successful implementation of major reservoir construction plans. The several facets of reservoir development plan related to formation sand prediction are noteworthy in figure 4.2. This incorporates management and control of sand.

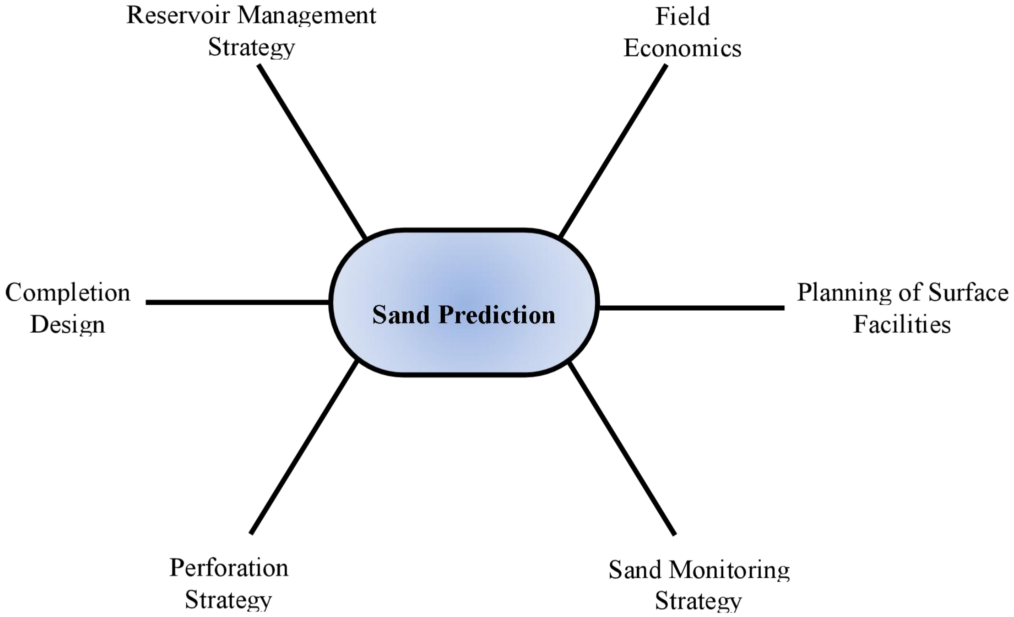


Fig. 4.2: Sand Prediction Applications

FIG 4.2: Sand Prediction App Lications

Risk quantification is mentioned in step 12 of the itemised step-by-step sand prediction, control, and management process as a way to choose which sand management method to use. A screening criterion to choose a likely candidate for sand control is shown in table 4.4 below. This is predicated on the danger of sand production in relation to environmental limits, well economics, and safety.

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	---	---	---	---	✓

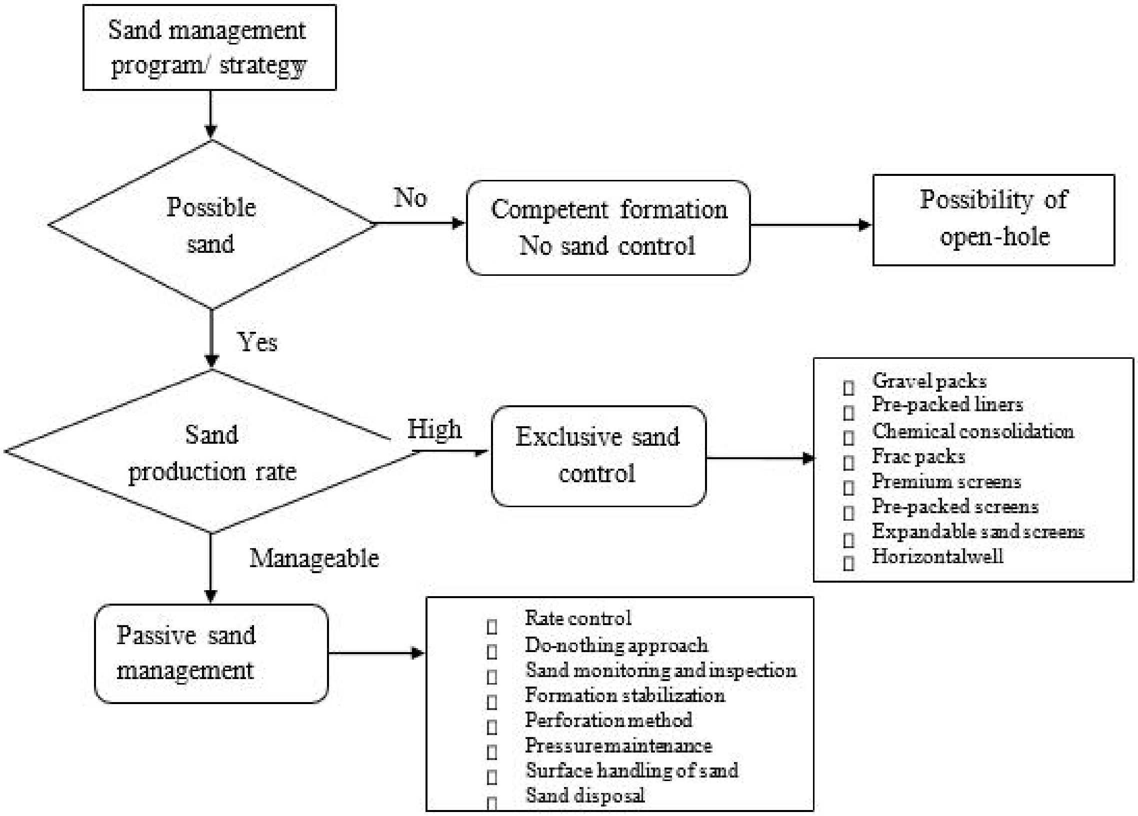


Fig. 4.3: Sand Management Strategy Flow Chart

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

Application Area Sand Control Type	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.

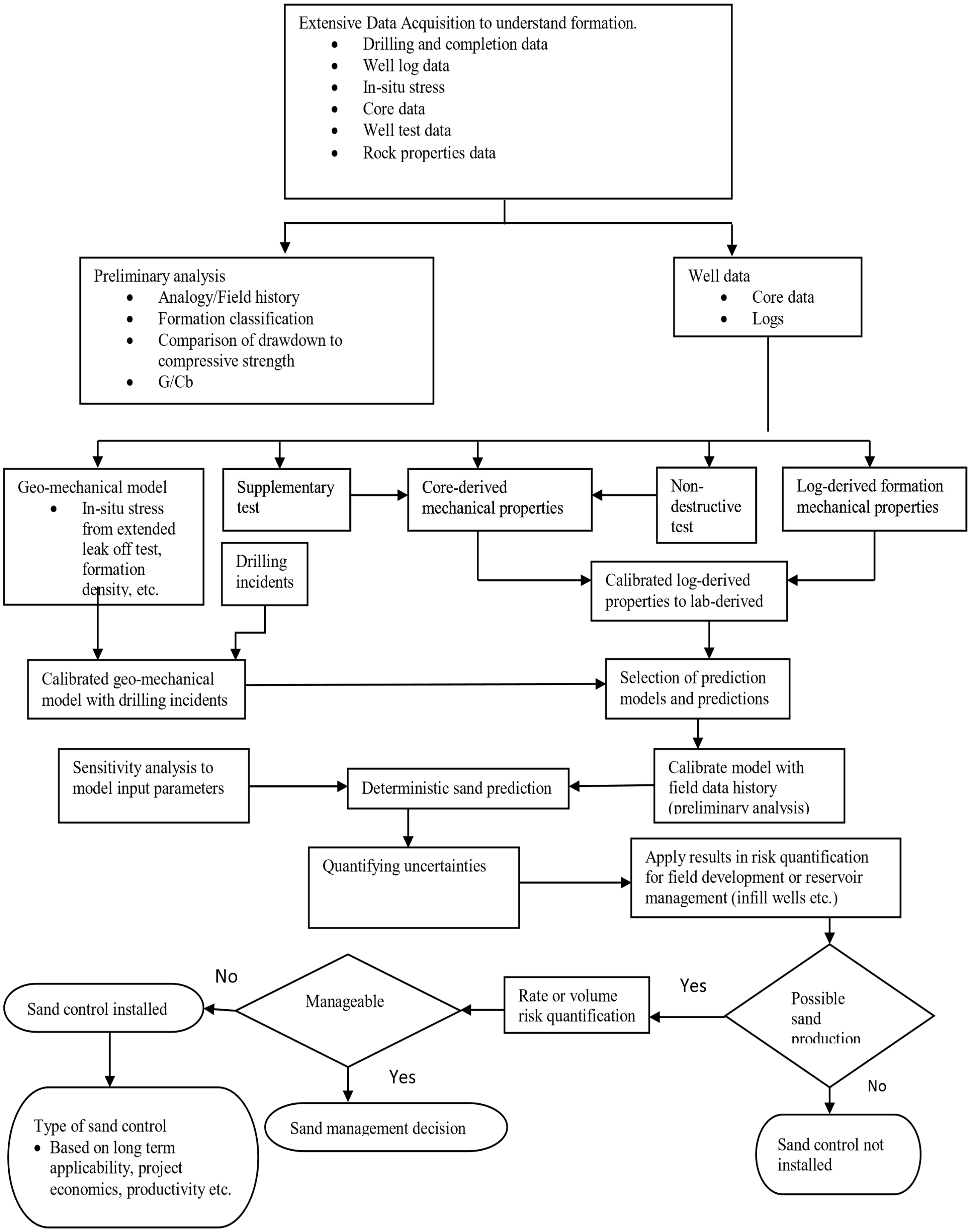


Fig 4.4: Flow Chart for Effective Sand Prediction, Control and Management

FIG 4.4: CHART FOR EFFECTIVE SAND PREDICATION, CONTROL AND MANAGEMENT

CHAPTER 5

DISCUSSION OF FINDINGS, CONCLUSIONS AND RECOMMENDATIONS

5.1 DISCUSSION OF FINDINGS

The findings from this study highlight that sand production remains one of the most serious operational challenges in unconsolidated reservoirs, often causing damage to production equipment, wellbore instability, and high maintenance costs. The study compared various sand prediction, control, and management techniques and found that combining prediction and monitoring tools with suitable control methods gives the best production stability.

Figure 1 in the results chapter illustrated the major mechanisms of sand production, which include shear or compressional failure, tensile failure, and pore collapse. The discussion revealed that in unconsolidated formations, shear failure is the most dominant cause of sand production due to the weak bonding of grains and high drag forces from fluid flow. This agrees with Al-Awad (2001), who stated that shear forces are primarily responsible for rock disintegration during fluid movement. Tensile failure was observed to occur under high drawdown pressure, while pore collapse was mainly linked with high-porosity formations such as sandstone and chalk. Therefore, the mechanisms described confirm that sand failure is highly dependent on the stress conditions and the physical properties of the reservoir rock.

From Table 3.1, the formation density data further supported that unconsolidated formations with high porosity values between 30 and 34 percent are more likely to produce sand. This finding is consistent with Veeken et al. (1991), who noted that unconsolidated formations typically have travel times greater than 100 microseconds per foot, indicating weak compaction. The study showed that porosity, formation strength, and in-situ stresses are the three most important parameters influencing sand prediction accuracy.

The sand prediction procedures outlined in Table 4.1 and Table 4.3 demonstrated that an integrated approach using both field data and analytical models provides the best prediction outcomes. When data from geological logs, well tests, and rock mechanics are combined, engineers can estimate the onset of sand production more reliably. This aligns with the findings of Qui et al. (2006), who recommended integrating different prediction models to minimise uncertainty. The study also observed that sand prediction should precede any field development plan since it helps determine whether to apply sand control or sand management strategies. This observation supports the view of Muhammad and Rasol (2025), who stressed that prediction accuracy directly influences the choice of management method.

The results further indicated that the choice of sand control method depends on formation characteristics and economic factors. Table 3.2 and Table 3.3 provided guidelines for selecting control methods in new and old wells respectively. Gravel packing, sand screens, and chemical consolidation were identified as effective in limiting sand influx in weak formations. However, in highly unconsolidated reservoirs, a combination of gravel packs and resin-coated sand proved most reliable, as it provided both mechanical and chemical stability. This finding corresponds with Abubakar et al. (2012), who found gravel packing to be one of the most effective and widely used techniques in Nigerian fields.

Emerging technologies, including Autonomous Inflow Control Devices (AICDs) and nanoparticle-based systems, were highlighted as promising alternatives. These devices regulate fluid inflow and prevent sand mobilisation by reducing velocity variations in the wellbore. The study found that AICDs improved flow distribution and extended well life. This observation agrees with Kumar et al. (2020), who reported that AICDs lower rig time and enhance completion efficiency. Nanoparticle additives were also found to increase the compressive strength of sand packs, reducing sand production by more than 80 percent, consistent with findings by Saghandali et al. (2023).

In terms of monitoring, Figure 3 and Figure 4 presented the application of Acoustic Sand Detectors (ASD) and Distributed Acoustic Sensing (DAS) systems. The results revealed that while traditional ASDs are simple to use, they are limited in pinpointing the exact sand entry points. Advanced systems like DAS and Distributed Temperature Sensing (DTS) offer real-time, continuous monitoring along the wellbore, providing early detection of sand influx. This finding agrees with Gardner et al. (2015) and Li et al. (2022), who showed that DAS and DTS technologies enhance sand management by offering high-resolution data on wellbore conditions. The integration of Machine Learning (ML) algorithms was also discussed as a cost-effective method for predicting future sanding trends using big data, consistent with Abdelghany et al. (2023).

The sand modelling process described in Figure 4.1 and Figure 4.2 demonstrated that prediction, control, and management must operate as a single system. By quantifying uncertainties and conducting sensitivity analysis, engineers can identify which parameters most affect sand production. Table 4.4 also presented a screening criterion for selecting candidate wells for sand control, based on risk level, environmental safety, and project economics. This integrated approach confirmed that effective sand management depends not only on technical efficiency but also on cost-effectiveness and environmental compliance.

Another key observation from the findings is the benefit of horizontal wells in reducing sand production. Horizontal wells were found to reduce fluid velocity and frictional drag, which are major contributors to sand mobilisation. This supports Igbokoyi (2011), who observed that horizontal wells in unconsolidated sands significantly decreased sanding compared to vertical completions.

The final Figure 4.3 illustrated a complete flowchart showing how risk quantification guides the selection between sand control and management. The figure demonstrates that in low-risk situations, sand management is more economical, whereas in high-risk conditions, control measures such as gravel packing and chemical consolidation are necessary. This structured approach matches the recommendation of Morita and Boyd (1991), who emphasised the importance of combining prediction, control, and monitoring to achieve sustainable production.

The findings confirm that sand production cannot be completely eliminated, but its impact can be reduced through accurate prediction, appropriate control methods, and continuous monitoring. The study concludes that adopting a step-by-step integrated strategy, as outlined in Tables 4.1 to 4.5 and Figures 4.1 to 4.4, ensures safer, more efficient, and economically viable production in unconsolidated reservoirs.

5.2 SUMMARY

Several sand prediction, control and management strategies were covered in chapter two of this study in order to accomplish the aforementioned goals. The four primary categories of prediction methods discussed in Chapter 2 are laboratory simulation, analytical, empirical and numerical. To accurately forecast a formation's capacity for sanding, several methods must be combined. In chapter three, developed efficient sand prediction approaches were given, with a focus on formation strength, which was shown to be a crucial prediction parameter. Sand prediction is found to be a determining factor in the choice between sand management (passive) and sand control (exclusive). Because of this, forecasting is crucial for field or well development. Chapter 3 also included sand management techniques and sand control selection techniques.

Reservoir management is aided by knowledge of a formation's sanding potential. Chapter 4 outlines a step-by-step process for managing, controlling and predicting sand. Flowcharts and screening criteria are also provided to aid in the selection of candidates for sand control. In the management of sand production, extensive planning and data collection are crucial. Chapters 3 and 4 of this work reflect the significance of this. The first step in choosing between sand control and management is prediction, which needs to be done carefully because errors might result in well loss.

5.3 CONCLUSIONS

The following inferences and conclusions are drawn from this study's theoretical research and empirical observations:

1. Optimizing wells or reservoirs requires integrating sand prediction, control, and management.
2. A better assessment of the sanding potential and useful understanding of the formation sand production behavior are provided by the incorporation of sand prediction techniques.
3. Sand disposal and strict well and facility monitoring are two ways that sand management plan affects the economy.
4. A methodical process for efficient sand management, control, and prediction has been created.
5. Sensitivity analysis aids in future research, and quantifying sand forecast uncertainties will increase the degree of trust in applying results in reservoir development.

5.4 RECOMMENDATIONS

The following recommendations are put forth in light of the study's scope:

1. To improve accuracy, techniques that can evaluate the formation strength in-situ should be developed, as it is a crucial parameter in sand prediction.
2. Future research can focus on creating a decision tree that includes economic consequences and the likelihood that the specified step-by-step approach will be successful.

APPENDIX

Table 1: UCS Models for Sandstones

Model and Reference	Equation	Remarks
Dt-McNally (McNally, 1987)	$C_0 = 185213e^{-0.037Dt}$	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)	$C_0 = 145\times10^{-12}(114+97V_{clay})K_b E_{dyn}$	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)	$C_0 = 2.27\times10^{-10} M^2\times[(1+\nu)/(1-\nu)]^2(1-2\nu)(1+0.78V_{clay}$	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

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