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Acknowledgement

بسم الله الرحمن الرحيم

{ وَقُلْ رَبِّ زِدْنِي عِلْمًا } سورة طه، الآية 114

الحمد لله على توفيقه وإعانتة، والصلاة والسلام على أشرف المرسلين .

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Dedication

بسم الله الرحمن الرحيم
الحمد لله الذي وفقني وأعانني ومنحني القوة والصبر لإتمام هذا العمل

“On the road to success, people will see your achievements, but only a few will understand the battles you fought silently to reach them. Stay grateful, stay humble, and never forget those who stood beside you when the journey was difficult.”

I dedicate this humble work to my beloved family, whose love, sacrifices, and support have been my greatest source of strength.

To my father, thank you for your endless sacrifices, hard work, and unwavering belief in me. You shaped the person I am today, and I will forever be grateful for everything you have done for my future .

To my mother, the person who waited for this moment the most, this achievement is as much yours as it is mine. Your prayers, love, and support carried me through every challenge. I only hope I have made you proud.

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Houssemeddine MEKKAR

Dedication

" To those who never stopped believing in me, even when I stopped believing in myself "

To the two people who gave me life, love, and everything in between my beloved mother and father, whose prayers, sacrifices, and unconditional love have been the light guiding every step of my journey. No words will ever be enough.

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And finally, to every soul in this world whose heart beats with the name of Barcelona to every dreamer who knows that no matter how difficult the match gets, you never stop fighting until the final whistle.
Més que un club.

Mohammed AYACHI AMOR

Abstract

ملخص

إنتاج الرمال هو مشكلة رئيسية ومتكررة في صناعة النفط، مما يؤدي إلى انخفاض في إنتاجية الآبار المنتجة بسبب تلف التكوين وفقدان سلامة البئر. يهدف هذا العمل إلى دراسة آليات إنتاج الرمال وطرق معالجتها. تمت دراسة الآبار المرشحة Well 1 و Well 2 و Well 3 في هذا السياق من خلال جمع وتحليل بيانات الإنتاج: معدل إنتاج الرمل 800 جرام/ساعة؛ محتوى الرواسب الأساسية والماء BSW بنسبة 41٪؛ بيانات اختبار البئر؛ بيانات النظام الصوتي؛ ورقة سلامة البئر. استخدام برنامج PROSPER سمح بتوضيح منحنى الإنتاج مقابل الضغط IPR للآبار مع وبدون إكمال التحكم في الرمال. تم إجراء اختبار منخل على عينتين من نوعين من صخور الخزن Cambrien و TAGI، حيث تم تحديد توزيع حجم الحبيبات من 0.01 مم إلى 4 مم. أظهرت النتائج أن إدارة التدفق السطحي سمحت بتقليل إنتاج الرمال. ومع ذلك، فإن إدارة السطح وحدها غير كافية لمعالجة هذه الظاهرة بالكامل، حيث قد تكون المشكلة ناتجة من عمق البئر، كما لوحظ في البئر Well 3. علاوة على ذلك، فيما يتعلق بالتكلفة، يُقدَّر اختبار تدفق الرمال بحوالي 220,000 دولار أمريكي ويمثل حلاً دورياً فقط، بينما يمكن تنفيذ حل دائم بتكلفة 1,110,000 دولار أمريكي.

الكلمات المفتاحية :

التحكم في الرمال، ضرر التكوين، الإنتاجية، سلامة البئر، حجم الحبيبات، تحسين الإنتاج، إدارة الرمال، PROSPER.

Résumé

La production de sable est un problème majeur et récurrent dans l'industrie pétrolière, entraînant une baisse de la productivité des puits producteurs en raison des dommages à la formation et de la perte d'intégrité du puits. Ce travail vise à étudier les mécanismes de la production de sable et les méthodes pour y remédier. Les puits candidats Well 1, Well 2 et Well 3 ont été étudiés dans ce contexte à travers la collecte et l'analyse des données de production : un taux de production de sable de 800 g/h ; une teneur en sédiments et eau de base BSW de 41 % ; des données de test de puits ; des données du système acoustique ; et la fiche d'intégrité du puits. L'utilisation du logiciel PROSPER a permis d'illustrer la IPR des puits avec et sans complétion de contrôle de sable. Un test de tamisage a été effectué sur deux échantillons de deux types de roches réservoirs Cambrien et TAGI, à partir desquels la distribution granulométrique a été déterminée de 0,01 mm à 4 mm. Les résultats ont montré que la gestion des flux de surface a permis une réduction de la production de sable. Cependant, la gestion de surface seule est insuffisante pour résoudre pleinement ce phénomène, car le problème peut provenir du fond du puits, comme observé dans le puits

Well 3. De plus, en ce qui concerne le coût, les tests de retour de sable sont estimés à 220,000 USD et ne représentent qu'une solution périodique, tandis qu'une solution permanente peut être mise en œuvre pour 1,110,000 USD.

Mots clés :

Contrôle du sable, Endommagement de formation, Productivité, Intégrité de puit, Granulométrie, Optimisation de production, Management de sable, PROSPER.

Abstract

Sand production is a major and recurring problem in the oil industry, causing a decline in the productivity of producing wells due to formation damage and the loss of well integrity. This work aims to study the mechanisms of sand production and the methods to address it. Candidate wells Well 1, Well 2 and Well 3 were studied in this context through the collection and analysis of production data: a sand production rate of 800 g/hr; a Basic Sediment and Water content BSW of 41%; well test data; acoustic system data; and the well integrity sheet. The use of PROSPER software allowed for illustrating the IPR of the wells with and without sand control completion. A sieve test was conducted on two samples of two types of reservoir rocks Cambrian and TAGI, from which grain size distribution was determined 0.01mm to 4mm. The results showed that surface flow management allowed a reduction in sand production. However, surface management alone is insufficient to fully address this phenomenon, as the problem may originate downhole, as observed in Well 3. Furthermore, regarding cost, sand flowback testing is estimated at 220,000 USD and represents only a periodic solution, while a permanent solution can be implemented at 1,110,000 USD.

Key words:

Sand control, Formation damage, Productivity, Well integrity, Grain size, Production optimization, Sand management, PROSPER.

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List of abbreviations

Φ	Porosity
V_p	Pore volume (m ³)
V_b	Bulk rock volume (m ³)
V_m	Volume of solid particles composing the rock matrix (m ³)
W_{dry}	Total dry weight of the rock (g)
ρ_{matrix}	Matrix density (g/m ³)
k	Permeability (mD or m ²)
Q	Flow rate (cm ³ /s or m ³ /s)
P	Pressure (psi)
L	length (m)
A	Area (m ²)
μ	Viscosity (cp)
S_o	Oil saturation (%)
S_g	Gas saturation (%)
S_w	Water saturation (%)
σ	Stress (Pa)
F	Force (N)
E	Young's modulus
s	Skin factor
ΔP	Pressure drop
ΔP_s	Pressure drop due to skin effect
Bo	Oil formation volume factor (m ³ /STB)
PG	Reservoir pressure
Pwf	Bottom well pressure
n_s	Number of slots per 1 m
F_s	External surface area per meter
w_e	Slot width on the expanded pipe (in)
m	Number of links between slots over the pipe cross section area
D_f	Final (expanded) pipe outer diameter (in)
D_i	Initial outer diameter of the pipe (in)
w_s	Slot width before expansion. (in)

FE	Flow efficiency (%)
q_s	Flow rate from damaged well (STB/d)
q_0	Hypothetical flow rate from undamaged well (STB/d)
r_e	Drainage radius of well (ft)
r_w	Wellbore radius (ft)
C	Empirical constant
v_p	Fluid velocity (ft/s)
ρ_m	Mixture density (lbs_m / ft^3)
UCS	Uniaxial compressive strength
TWC	Thick wall cylinder
NORSOK	Norwegian Continental Shelf Competitiveness Position
ISO	International Organization for Standardization
API	American petroleum institute
BOP	Blow out preventer
DHSV	Downhole safety valve
SCON	Chemical consolidation
FO	Fibre optic
DTS	Distributed Temperature Sensing
DAS	Distributed acoustic sensing
SCEs	Surface safety critical elements
MSFR	Maximum sand free rate
ASD	Acoustic sand detector
SSV	Subsurface safety valve
WIMS	Well integrity management system
WFM	Well failure model
SCP	Sustained casing pressure
ML	Machine learning



General Introduction

General Introduction

Poorly consolidated reservoirs, where the lack of mineral cementation makes rock grains prone to sand formation, contain over 70% of the world's hydrocarbon reserves [1]. This phenomena can occur in well cemented, high compressive strength rocks as well as unconsolidated formations. It can start right away or evolve throughout the course of the well's life [2].

Uncontrolled sand production has serious safety and economic effects, including loss of well control, blowouts, production shut-in, equipment erosion, and pipeline accumulation limiting reservoir extraction. Millions of dollars are spent each year on sand removal, which ultimately ends the productive life of both well and reservoir [3].

Affected regions include the U.S. Gulf Coast, the North Sea, China, Canada, California, Venezuela, Western Africa, Indonesia, and Malaysia [3]. Sand control methods mechanical (screens, gravel packs, frac packs), chemical in-situ consolidation, and combined are selected based on particle size distribution analysis, each carrying distinct design criteria and operational challenges.

In Algeria, several fields are affected by sand production problems. In the field of study, Hassi Berkine, sand production in some wells ranges between 100 and 1000 lb/day during sand flowback tests [4]. This method is used to produce free sand and determine the appropriate production rate with minimum sand production by restricting the pressure drawdown between the reservoir pressure and the well's bottomhole pressure. However, as sand management methods, these are not permanent solutions for sand control, and they involve high operational costs and risk of damaging surface equipment, flowlines, flare lines.

The study investigates the underlying mechanisms triggering sand production in unconsolidated reservoirs, examines its detrimental effects on well integrity and formation stability, and identifies the most suitable sand control strategies for the specific geological conditions of local production fields.

Reservoir depletion increases effective stresses beyond the formation's unconfined compressive strength, leading to structural rock failure at the borehole and perforation tunnel walls. Water breakthrough further exacerbates this condition by diminishing grain-to-grain cohesiveness through the reduction of capillary surface tension and the dispersion of amorphous bonding materials. High-velocity production streams entraining abrasive sand

particles cause rapid erosion of safety-critical completion elements, posing a direct threat to downhole and surface equipment integrity.

This thesis aims to analyze unconsolidated reservoir characterization and the causes leading to sand production, highlight the importance of well integrity monitoring in such conditions, and propose appropriate sand control methods suited to the nature of Algerian reservoirs.

Chapter one covers the geological and reservoir context of sand production, the mechanisms involved and their consequences, the impact on formation damage, and the effects on well integrity.

Chapter two includes mechanical and chemical control methods, the design criteria governing their selection, evaluation of their efficiency, and well integrity monitoring and mitigation measures.

Chapter three presents the studied field and sand-affected wells, highlighting the sand management techniques applied and the results of laboratory sieve analysis conducted on different reservoir cores. A design is then developed based on these results, and the proposed methods are simulated using dedicated simulation software.

The thesis concludes by presenting the main findings of the study, along with perspectives and recommendations for optimized reservoir production. It also highlights key considerations for sand control in offshore wells, given Algeria's anticipated investment in offshore reservoir development in the near future.

1 | Chapter

Theoretical Background on
Sand Production and
Wellbore Integrity

Introduction

Assessing the geomechanical triggers of solids production begins with the classification of sedimentary rocks and their inherent mechanical properties. Terzaghi's relationship defines the fundamental principle of effective stress, where reservoir depletion increases the load transmitted through the solid rock matrix. Once induced stresses exceed the unconfined compressive strength, formation failure initiates, driven by hydrodynamic drag and reduced intergranular cohesion. Such uncontrolled influx compromises well integrity, defined as the technical and operational solutions designed to prevent the release of formation fluids. Abrasive particle entrainment causes rapid erosion of safety-critical elements, threatening the maintenance of two independent barrier envelopes. Quantifying this impairment through mechanical skin and flow efficiency provides the technical foundation for evaluating the sand control strategies developed in this work.

I.1 Geological and reservoir context of sand production

I.1.1 Sedimentary rock formation and lithification

Sedimentary rocks are formed as sediments, originating either from eroded fragments of older rocks or from chemical precipitates. The transformation of these loose sediments into solid rock occurs through the process of diagenesis, which includes lithification by both compaction and cementation. Compaction occurs as grains are squeezed together into a denser mass due to increasing overburden pressure from additional layers of sediment. Simultaneously, cementation involves the precipitation of minerals into the intergranular or intercrystalline pore spaces, binding the particles together [5]. Common cements include quartz, which can form through hydrothermal activity, weathering, or during deep burial [6].

I.1.2 Classification of sedimentary rocks

Sedimentary rocks are fundamentally classified into two main groups based on their origin: Clastic and Chemical/Biochemical.

I.1.2.1 Clastic (terrigenous) rocks: These are formed from the weathering and fragmentation of pre-existing minerals and are classified by texture and grain size. They are divided into coarse-grained (conglomerates), medium-grained (sandstones), and fine-grained (siltstones, mudstones, and shales). Fine-grained rocks are further classified by their structure; for example, mudstones with well-developed parting parallel to beds are termed shales [5].

I.1.2.2 Chemical/biochemical rocks: These form through chemical processes, such as the precipitation of calcite (the main constituent of limestone) from the remains of marine

organisms. Dolomite is formed when limestone is transformed through dolomitization, usually requiring specific magnesium-to-calcium ratios in the diagenetic solutions [5].

I.1.2.3 Evaporites: These result from the evaporation of seawater and include deposits like gypsum and halite; while they do not typically form reservoirs, they are essential as cap rocks and trap generators [5].

I.1.3 Petrophysical properties of reservoir rocks

Petrophysics is the study of the physical, mechanical, electrical, and thermal properties of reservoir rocks and their interactions with fluids. The primary characteristics include :

I.1.3.1 Physical properties

- **Porosity:** This is the ratio of void space to the total bulk volume of the rock, reflecting its storage capacity (Figure I.1). Primary porosity is developed at the time of deposition, while secondary porosity results from post-depositional processes like dissolution or fracturing. Effective porosity refers only to the interconnected pore volume available for fluid flow [7].

Porosity is calculated using the relationship:

$$\Phi = \frac{V_{pore}}{V_{bulk}} = \frac{V_{bulk} - V_{matrix}}{V_{bulk}} = \frac{V_{bulk} - \frac{W_{dry}}{\rho_{matrix}}}{V_{bulk}} \quad (I.1)$$

where:

V_{pore} = pore volume (m³).

V_{bulk} = bulk rock volume (m³).

V_{matrix} = volume of solid particles composing the rock matrix (m³).

W_{dry} = total dry weight of the rock (g).

ρ_{matrix} = mean density of the matrix minerals(g/m³).

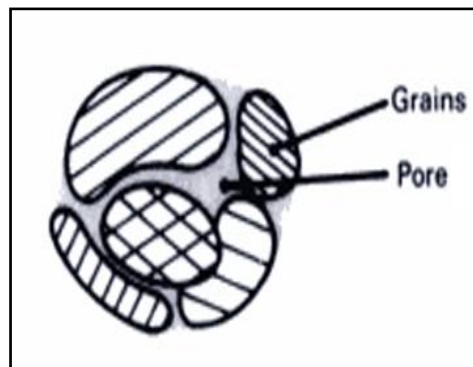


Figure I.1: Schematic showing the porosity between the grains [8].

- **Permeability:** This property measures the ease with which a fluid can flow through the interconnected pores of a rock. It is measured in darcies or millidarcies. Absolute permeability is calculated with only one fluid present, while effective permeability considers

the presence of immiscible fluids like oil and water. Relative permeability is the ratio of effective to absolute permeability and is a strong function of fluid saturation [9].

The fundamental equation of permeability calculation defined by Darcy:

$$Q = \frac{K A (P_i - P_o)}{\mu L} \quad (1.2)$$

where:

Q = the flow rate (cm³/s or m³/s)

P_o = the outlet fluid pressure (dynes/cm² or Pa)

P_i = the inlet fluid pressure (dynes/cm² or Pa)

μ = the dynamic viscosity of the fluid (poise or Pa.s)

L = the length of the tube (cm or m)

k = the permeability of the sample (darcy or m²)

A = the area of the sample (cm² or m²)

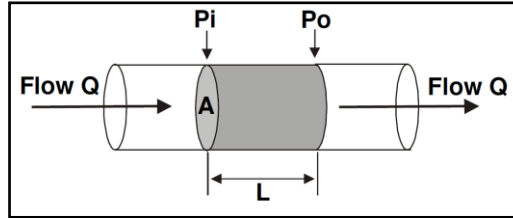


Figure I.2: Schematic representation of fluid flow through a porous medium [9].

- **Fluid saturation:** This is the fraction of pore volume occupied by a specific fluid (gas, oil, or water). Reservoirs typically show vertical separation due to gravity, with gas at the top, oil in the middle, and water at the bottom. Irreducible water saturation is the level where water is held by capillary pressure and will not flow [10].

Saturation given by :

$$S_o + S_w + S_g = 1 \quad (1.3)$$

Where :

$$S_o = V_o / V_p \text{ (\%)}$$

$$S_g = V_g / V_p \text{ (\%)}$$

$$S_w = V_w / V_p \text{ (\%)}$$

- **Wettability and capillary pressure:** Wettability is the tendency of a fluid to adhere to a solid surface in the presence of another immiscible fluid. Capillary pressure is the pressure variation between these fluids and is often sufficient to prevent the flow of one fluid into the pores occupied by another [10].

I.1.3.2 Mechanical properties

- **Stress:** For structures having a finite surface, the idea of stress is introduced, which is

defined as the force divided by the area. The normal stress is the normal force divided by the area [11].

Equation of stress:

$$\sigma = F/A \quad (1.4)$$

Where:

σ : Stress (Pa)

F: Force (N)

A: Area (m²)

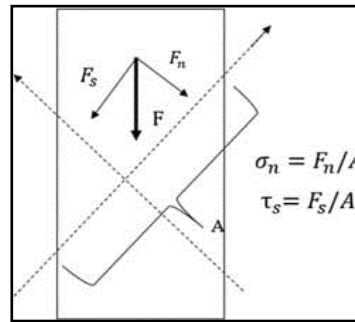


Figure I.3: Force vector [11].

- **Strain:** When a structure is subjected to stress, it deforms. The strain, which expresses the intensity of the deformation, can be divided into two types: normal strain, which is the deformation in the x, y, and z directions divided by the length for each direction, and angular strain, which is the angular deformation between the xy, yz, and zx faces.

Strain: $\epsilon = d/L$ [11]

- **Stress and strain:** When a rock specimen or earth element is subjected to load, it will deform. The higher the stress level, the greater the strain on the rock [11].

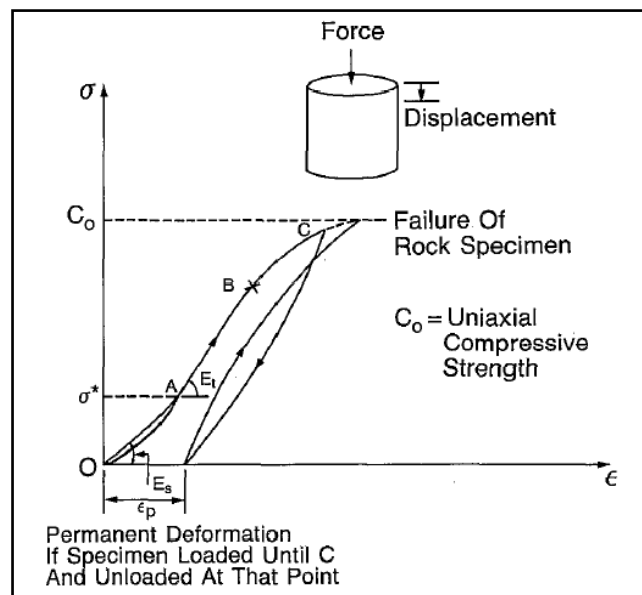


Figure I.4: Typical stress/strain curve [12].

Stage O to A: The curve is nonlinear as preexisting microcracks progressively close, causing the rock to stiffen; this response reflects the specimen's prior geological stress history.

Stage A to B: The stress-strain relationship becomes linear, defining the elastic regime governed by Young's modulus, which represents the rock's resistance to deformation under applied loading.

Beyond point B: Irreversible damage initiates and large deformations develop, rendering a single elastic constant insufficient to describe rock behavior; a secant or tangent modulus must instead be introduced to characterize the post-elastic response [12].

- **Elastic constants:** Rocks have several connected elastic moduli that dictate their stress strain relationships, including:

Young's Modulus (E): The proportional constant between vertical normal stress and vertical strain, it characterizes the rigidity of the material.

Poisson's Ratio (ν): The ratio of lateral deformation to vertical deformation when a rock is subjected to stress.

Shear Modulus (μ): The proportional coefficient relating shear stress to angular/shear deformation.

Bulk Modulus (K): Represents the rock's resistance to uniform compression.

Biot Coefficient (α): A poro-elastic constant that relates pore pressure to the effective stress acting on the rock matrix [11].

I.1.4 Principle of effective stress

The concept of effective stress is vital for analyzing structure stability in porous media.

- **Effective stress for deformation:** In Terzaghi's concept, the effective stress (σ_e) is equal to the total stress (σ) minus the pore pressure (p).
- **Effective stress for failure:** A rock sample will break when the effective stress exceeds its strength. For standard sedimentary rocks, all pores are typically connected, making the effective stress for failure approximately the same as effective stress for deformation [11].

I.1.5 Rock strength and failure criteria

The geomechanical limit of a reservoir is defined by its strength, which is measured through various tests:

- **Uniaxial compressive strength (UCS):** A primary rock strength parameter used to judge if the formation will fail during production.
- **Thick wall cylinder (TWC) strength:** Specifically used for medium-hard to hard formations to predict the onset of sand production by measuring the confining pressure at which a hollow cylinder fails.
- **Nonlinear behavior and plasticity:** High-level compression stress induces nonlinearity

in the stress-strain curve. This is caused by opening and closing microcracks (initial nonlinearity), shear-type microcrack growth, and pore collapse [13].

- **Failure progression:** Under high effective stress, a rock cavity wall progresses from the elastic region into plastic and eventually failure regions, potentially leading to sand production [11].

I.2 Mechanisms and consequence of sand production

There are three main sources of fine particles in petroleum-bearing formations:

- **External particles** introduced by injected fluids during completion, workover, and improved recovery operations. These fluids may contain iron colloids from corrosion, as well as sand, clay, microbial matter, and mud fines.
- **Internal particles** originating from the formation itself. These include clay and mineral species attached to pore surfaces, which can be mobilized by fluid incompatibility, rock–fluid interactions, hydrodynamic forces, or rock deformation. Chemical dissolution of cementing materials can also release particles [14].
- **Particles generated by chemical reactions**, such as salt precipitation from mixing injected Sea water with reservoir brine, sulfur formation during sour gas production, and precipitation of iron, silica gels, scales, and asphaltenes due to changes in fluid composition and thermodynamic conditions.

Particles attached to pore surfaces can be detached under changes in salinity, temperature, and flow velocity. Once mobilized, they are transported through porous media by mechanisms such as diffusion, adsorption, sedimentation, and fluid flow, influenced by forces like electrokinetic interactions, pressure, friction, and gravity.

As these particles migrate through the pore network, they may be trapped and deposited, altering the structure of the porous medium and reducing porosity and permeability. This process is commonly referred to as formation damage [14].

I.2.1 Conditions of sand production

Sand production occurs when two conditions are met:

- The rock fails when the applied stress exceeds its strength.
- The failed sand grains are mobilized and transported by the flowing fluids.

I.2.1.1 Rock failure: Sand production in oil wells occurs because the original pressure balance around the wellbore is disturbed, leading to yielding and failure of the formation rock structure. The mechanisms of rock failure include both mechanical failure and chemical failure.

A. **Mechanism of mechanical failure:** There are three types of mechanical failure mechanisms responsible for sand production in rocks:

- **Shear failure:** During production, pore pressure decreases and effective stress increases within the formation, leading to elastic deformation in hard formations and plastic deformation in soft formations. A plastic zone develops in the disturbed area, and shear failure occurs once the deformation exceeds a certain limit. As a result, solid particles are detached from the rock.
- **Tensile failure:** Sand production occurs when a sudden pressure change exceeds the tensile strength of the formation, causing enlargement of the perforation tunnel. This type of failure generally takes place at the tip and along the walls of the perforation tunnel when the effective stress surpasses the formation's tensile strength [13].
- **Cohesion failure:** This mechanism is particularly significant in weakly consolidated formations. Cohesion strength controls the resistance of exposed surfaces to erosion, such as perforation tunnels, open hole wellbore surfaces, hydraulic fracture surfaces, and shear planes. Cohesion is related to cementation and capillary forces. When the drag force from fluid flow exceeds the cohesion strength, sand production occurs. This type of failure is common in formations with low cohesion strength, such as unconsolidated sandstone, where cohesion is nearly zero [13].

B. **Mechanism of chemical failure:** Rock strength depends on contact forces, friction between particles, and cohesion provided by cementation. When movable water is present and begins to flow, chemical reactions between the water and formation materials can dissolve part of the cement, reducing rock strength.

The extent of sandstone failure due to chemical reactions can be evaluated by analyzing the cement composition. Certain clay minerals contribute significantly to this process:

- **Illite:** tends to swell and disperse after absorbing water, making it sensitive to flow velocity and water presence.
- **Illite/smectite mixed layers:** are transitional minerals that are easily dispersed.
- **Kaolinite:** has weak lattice cohesion, making it prone to particle migration and velocity sensitivity [13].

Studies of unconsolidated sandstone show that clay minerals mainly consist of illite (about 46%), followed by illite/smectite mixed layers (17%) and chlorite (15%), with kaolinite also present. These formations are characterized by weak consolidation and low critical flow velocity for sand production.

Additionally, water production further reduces rock strength, intensifying sand production issues. Due to strong sensitivity to both flow velocity and water, the impact of sand production must be considered when predicting well performance and managing production [13].

I.2.1.2 Forces effecting sand and particle transportation: The forces acting on particles in a flowing suspension within porous media are classified into three categories: forces related to transport mechanisms, forces related to attachment mechanisms, and forces related to detachment mechanisms. (Figure I.5) describes the various particulate processes that may occur in this context. These forces are characterised in terms of relevant dimensionless groups, as detailed in (Annex Table 1).

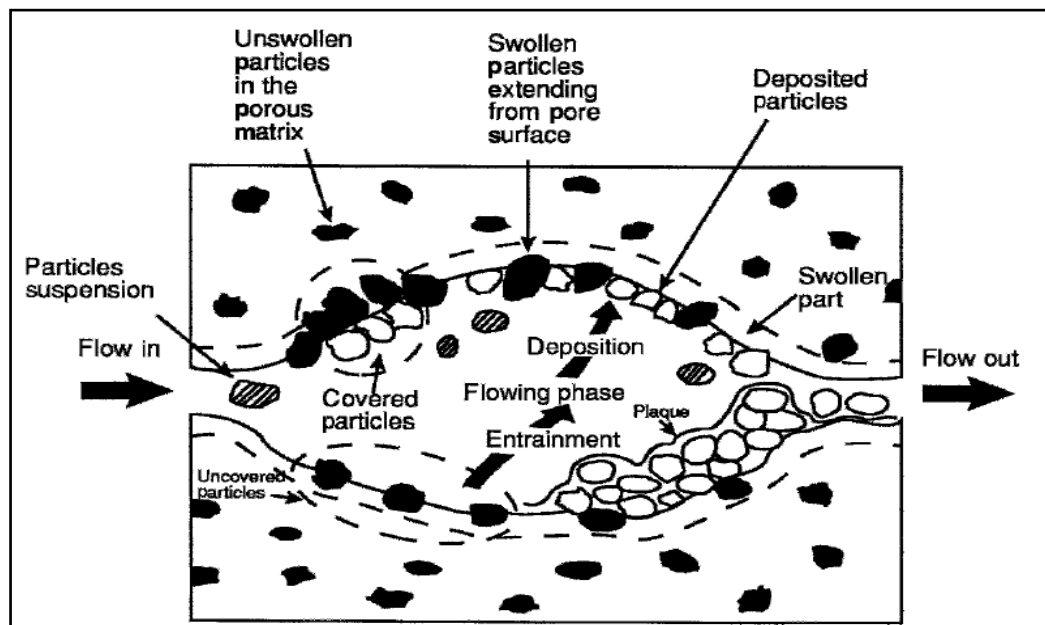


Figure I.5: Particulate processes in porous media [9].

I.2.2 Sand production mechanism

Sand production occurs when stress acting on particles exceeds rock strength. Rock strength depends on cement cohesion, fluid adhesion, friction between particles, and particle weight, while acting stresses include tectonic stress, overburden pressure, fluid drag force, pore pressure, and production drawdown [13].

1.2.2.1 Tectonic stress: Higher near faults and at structure tops, tectonic stress creates microcracks that weaken rock strength, making sand production more likely and severe, while lower structure areas experience less sand production [13].

1.2.2.2 In situ stress: Pore pressure decline increases effective stress, causing wellbore stress concentration and perforation tunnel failure. Pressure reduction intensifies shear failure in unconsolidated formations. Drilling and production disturb the original formation

equilibrium, and continued pressure decline beyond the elastic limit initiates and worsens rock failure and sand production. Insufficient water injection further increases load on the rock skeleton, causing outward formation expansion [13].

1.2.2.3 Rock strength: Rocks with uniaxial compressive strength below 7.0 MPa are weakly consolidated and prone to sand production. Cementation failure resulting from shear stress, tensile stress, or fluid dissolution releases discrete particles. Shallow formations and clay-cemented sandstones are particularly weak due to clay instability and sensitivity to external conditions [13].

1.2.2.4 Formation heterogeneity: Variations in in situ stress and permeability cause different stress responses and failure modes across the formation. In weakly consolidated sandstones, stress heterogeneity promotes directional shear failure, breaking down the original formation structure [13].

1.2.2.5 Production drawdown: Increased drawdown reduces pore fluid pressure, raises effective stress, and weakens sand arching near the wellbore. When stress exceeds rock strength, the skeleton fails. Sudden changes in drawdown or operating conditions further trigger sand production [13].

1.2.2.6 Water production: Water breakthrough wets clay, reduces particle cohesion, and weakens rock strength, lowering the critical flow velocity for sand production. Water injection causes clay swelling and migration, further reducing cohesion and increasing sand production with rising water cut [13].

1.2.2.7 Fluid viscosity: Higher fluid viscosity increases drag force on surrounding rock, promoting failure and sand production particularly in heavy oil reservoirs [13].

1.2.3 Consequences of sand production

Sand production generally has detrimental effects on both short and long-term well productivity. While certain wells may operate under conditions of manageable sand production, such cases remain exceptional. In most instances, managing severe sand production over the well's lifetime is neither economically viable nor an advisable operational strategy [15].

1.2.3.1 Accumulation in surface equipment: When production velocity is sufficient to transport sand through the tubing, particles may accumulate in surface facilities such as separators, heater treaters, or production pipelines. Restoring production requires shutting in the well, opening the surface equipment, and manually removing the accumulated sand, incurring both cleaning costs and deferred production losses. Partial sand filling of a separator reduces its liquid handling capacity for instance, one cubic foot of sand in an

oil/water separator with a two-minute residence time reduces capacity by 128 barrels per day [15].

1.2.3.2 Accumulation downhole: When production velocity is insufficient to transport sand to surface, particles may bridge within the tubing or settle inside the casing, progressively covering the producing interval until the well becomes sanded up and production ceases. Remedial operations include running a bailer on slickline or circulating sand out using coiled tubing or a smaller-diameter string, the latter requiring careful execution to avoid the inner string becoming stuck. Where sand production is continuous, such clean-out operations may be required monthly or even weekly, resulting in significant production losses and increased maintenance costs [15].

1.2.3.3 Erosion of downhole and surface equipment: In highly productive wells, high-velocity fluid flow carrying sand causes severe erosion of both downhole and surface equipment as shown in (Figure I.6), leading to frequent maintenance and component replacement. If erosion persists or becomes sufficiently severe, complete equipment failure may result, creating serious safety and environmental issues alongside deferred production, and potentially requiring a rig-assisted workover operation [15].

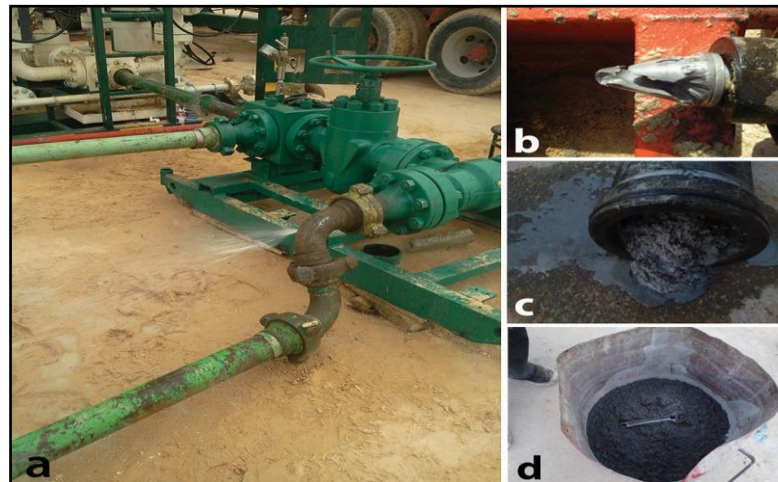


Figure I.6: Examples of erosion damage caused by sand production in upstream sites. A/ Eroded pipe elbow, causing loss of containment; B/ Eroded choke valve; C/ Pipe clogged by sand; D/ Sand disposal challenge [16].

1.2.3.4 Collapse of the formation: Large volumes of produced sand may create a void behind the casing that enlarges over time until the overlying shale or formation sand collapses due to loss of structural support. Following collapse, sand grains rearrange at lower permeability than originally existed an effect more pronounced in formations with high clay content or wide grain size distribution. Overlying shale collapse may result in complete

productivity loss. Formation collapse is particularly critical when collapsed material fills or partially fills perforation tunnels, as even small amounts of material within perforations can significantly increase near-wellbore pressure drop for a given flow rate [15].

I.3 Well integrity

I.3.1 Definition

Well integrity, basically defined as the use of technical, operational, and organizational options to limit the risk of uncontrolled fluid release during a well's life, serves as a core for safety, environmental preservation, and economic efficiency in the energy industry [17].

Many international standards define effective integrity management, including:

- NORSOK D -10: well integrity in drilling and well operations.
- ISO 16530-1 2017: well integrity lifecycle governance.
- NOG 135: Recommended guidelines for classification and categorization of well control incidents and well integrity incidents.
- API RP 14C: Analysis, Design, Installation and testing of safety systems for offshore production facilities.

I.3.2 Well barriers

Well barriers are applied to avoid spills and minimize the risks caused by drilling, production, and intervention operations.

According to NORSOC D-010 'Envelope of one or several dependent barrier elements preventing fluids or gases from flowing unintentionally from the formation into another formation or to surface' [18].

I.3.2.1 Well barriers objectives

The main objectives of the barriers:

- During regular production or well operations, prevent any significant hydrocarbon leakage from the well into the surrounding environment.
- Shut in the well in emergency shutdown and prevent hydrocarbons flow [18].

I.3.2.2 Barriers classification

- Primary Well Barrier: This is the first set of elements closest to the pressurized hydrocarbons.
- Secondary Well Barrier: This envelope acts as a supplement to the primary barrier, providing a

second layer of containment should the primary barrier fail [18].

The (Table I.2) represents different examples of primary and secondary barriers:

Table I.1: Examples of barriers systems through the lifecycle of the well [19].

Example	Primary barrier	Secondary barrier
Drilling	Overbalance mud with filter cake.	Casing cement, casing, BOP.
Production	Casing cement, casing, packer, tubing, DHSV.	Casing cement, casing, wellhead, tubing hanger, x-mass tree.
Intervention	Casing cement, casing, deep-set plug, overbalance mud.	Casing cement, casing, wellhead, BOP.
Plug & abandonment	Casing cement, casing, Cement plug.	Casing cement, casing, Cement plug.

I.3.2 Well integrity life cycle

According to ISO 16530-1 2017, well integrity management spans the entire well life cycle through six successive phases (Figure I.7). The basis of design phase establishes the framework by defining well objectives, identifying hazards, and developing a risk register. The well design phase develops the barrier plan, specifying casing schematics, cementing requirements, and operating limits. During the construction phase, barriers are verified to prevent uncontrolled flow and structural failure, with deviations addressed through a formal management of change process. The operations phase ensures continuous monitoring of pressures, flow rates, fluid composition, and annulus pressures, with anomalies investigated accordingly. The intervention phase addresses activities such as production enhancement, diagnostic work, and downhole repairs, maintaining barrier verification throughout. Finally, the abandonment phase establishes permanent barriers to prevent fluid escape, protect aquifers, and comply with legal requirements [20].

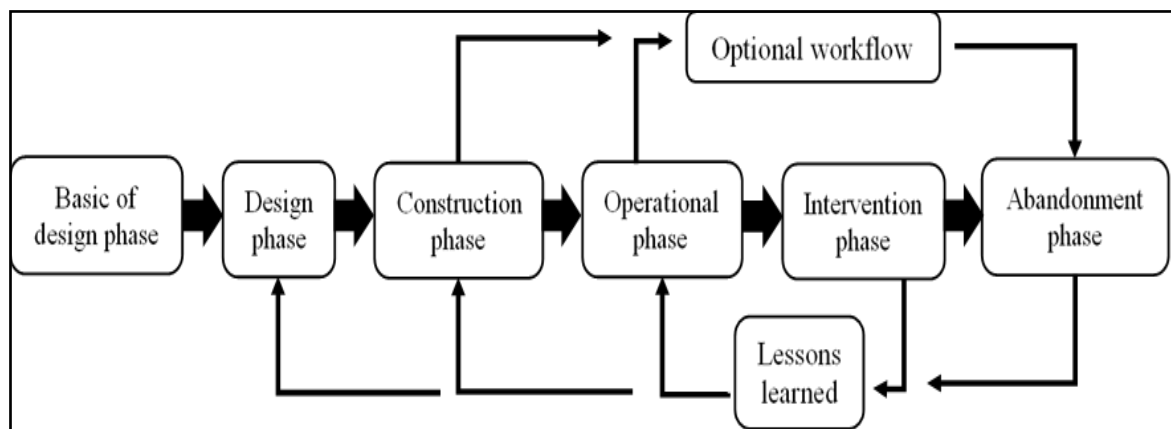


Figure I.7: Well integrity life cycle phases [20].

I.4 Impact of Sand Production on Formation Damage

I.4.1 Formation damage

I.4.1.1 Definition

Formation damage is the reduction of permeability in reservoir formations caused by various harmful activities during drilling, production, and other operations. It leads to decreased permeability, skin damage, and reduced well performance. Preventing formation damage is more effective than trying to restore it, and its management relies on validated models and properly designed laboratory and field studies [21].

The link between productivity loss and formation damage is depicted in (Figure I.8).

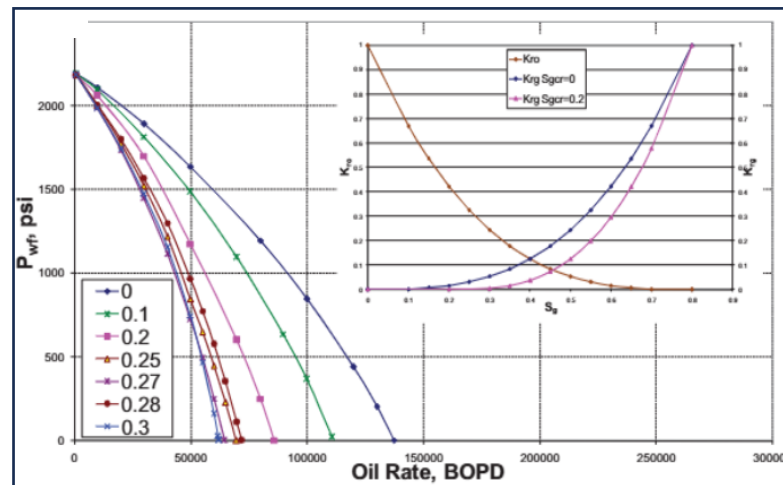


Figure I.8: Effect of formation damage on well productivity [22].

I.2.1.3 Formation damage characterization:

Several commonly used methods are available, including:

- Laboratory sampling and analysis
- Complete well history
- Well testing
- Laboratory sampling and analysis: Laboratory sampling and analysis is a key method for identifying damage or deterioration in oil and gas production systems. By examining rock, formation fluids, or other material samples in the lab, operators gain a detailed understanding of their chemical and physical properties. This insight is crucial for designing effective remediation strategies.
- Complete well history: A complete well history provides a detailed record of all events and activities from the initial drilling and completion stages through to current production and maintenance operations throughout the well's lifespan.
- Well tests: Well tests are essential for evaluating a well's performance and production.

Pump tests with clear pressure responses are the most effective way to determine if reservoir production is restricted. To accurately identify actual formation damage, it is important to recognize that the Total Skin Effect includes parasitic elements (pseudo skins) that need to be removed [12].

I.2.1.4 Location of damage:

Damage can occur in various parts of the fluid pathway, from the reservoir to the surface.

- At the bottom of the well.
- At the wellbore wall (External cake).
- Around the wellbore (Internal cake).

Figure I.9 below perfectly illustrates the zones of damage localization:

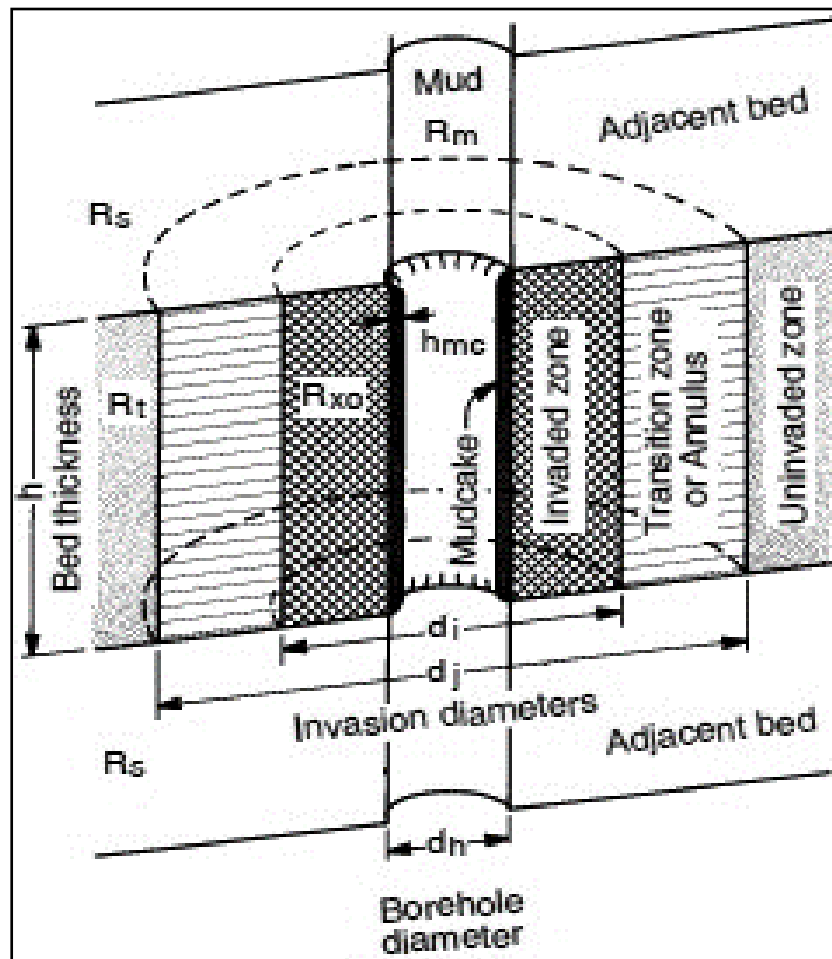


Figure I.9: Different zones of damage [23].

I.2.2 Skin

I.2.2.1 Definition: The skin factor (S) is a hydrodynamic parameter that quantifies the additional resistance to fluid flow near the wellbore, causing reduced production compared to an ideal, undamaged well [24].

I.2.2.2 The origin of skin:

❖ Perforations: While production is limited to the perforation holes when they are present, the ideal well model assumes full 360 degree contact with the formation. This difference causes a pressure loss represented by the skin factor, also known as the wellbore skin effect coefficient, which depends on the efficiency of penetration, as well as the number and distribution of perforations.

❖ Partial penetration: Partial penetration occurs when a well produces from a formation thickness smaller than the full exploitable height. This situation arises due to the presence of an argillaceous barrier or to prevent early breakthrough of water or gas.

❖ Overall damage: Additional pressure losses concentrated around the wellbore (matrix) can consistently be represented as a skin effect. Therefore, the combined impact of all these factors is reflected in the skin factor measured during testing [20] .

$$S_e + S_p + S_c = 1 \quad (I.5)$$

Where:

- S_e : the real damage around the wellbore (matrix)
- S_p : the pressure loss due to perforations
- S_c : the choke of the flow due to partial penetration.

I.2.2.3 The skin effect on productivity:

A. Notion of productivity index: The flow rate corresponding to the pressure difference between the bottom hole and the reservoir is known as the well's productivity index, or injectivity index. Under steady state radial flow conditions for a liquid [12], it quantifies the well's potential and is expressed as:

$$IP = \frac{Q}{P_g - P_f - \Delta P_s} \quad (I.6)$$

Where:

Q : the flow rate (m^3/h)

P_g : the pressure at the bottom of the well (bar)

P_f : the pressure at the top of the formation (bar)

ΔP_s : the pressure drop due to skin effect and other factors (bar)

The well's productivity index decreases if damage reduces the permeability around the wellbore, causing a higher pressure drop to maintain a given flow rate [12].

$$\Delta S = \frac{141.2 q_0 \mu_0 B_0}{K h} \quad (I.7)$$

Where:

μ_0 = oil viscosity (centipoise)

B_o = oil formation volume factor (m^3/STB)

K = permeability (darcy)

h = net pay thickness (m)

B. The effect of skin on productivity:

For an oil well, the IPR equation is written as:

$$q = \frac{P_G - P_{wf}}{141.2 \left(\ln \left(\frac{r_e}{r_w} + S \right) \right)} \quad (I.8)$$

Where:

r_e = Drainage radius (ft)

r_w = Wellbore radius (ft)

I.2.2.4 Types of skin

A. Mechanical skin: Mechanical damage refers to the invasion of solid particles into natural fractures, the tight rock matrix around the wellbore, or the fracture face during overbalanced drilling, completion, or hydraulic fracturing operations. In tight formations, natural fractures are particularly vulnerable because they have very small apertures, so even fine solids can easily plug them. In sandstone reservoirs, this type of damage is often difficult to remove because acid treatments are not always effective. [25]

The skin due to mechanical damage can be expressed with the following equation:

$$S_m = \left[\frac{1-M_f}{M_f} \right] \ln \left(\frac{r_d}{r_w} \right) \quad (I.9)$$

Where M_f is the ratio between the damaged zone permeability k_d and the undisturbed formation permeability k_f

$$M_f = \frac{K_d}{K_f} \quad (I.10)$$

B. Bi-phase skin: Bi-phase skin (S_n) is an additional skin effect that appears during injection tests when two fluid phases are present in the reservoir, typically the injected water (or brine) and the original oil.

It is caused by the mobility contrast between the two fluids, meaning they do not flow equally easily through the rock. This difference distorts the flow behavior near the wellbore and creates an extra pressure drop, which is interpreted as additional skin.

During injection, a zone forms around the well where water saturation is high, while the outer region still contains mostly oil. These two zones have different mobilities and compressibilities, leading to the development of bi-phase skin. [26]

$$S^* = \left[\frac{1-M_b}{M_b} \right] \ln \left(\frac{r_d}{r_w} \right) \quad (I.11)$$

where M_b is the ratio between the mobility of the displacing fluid and the reservoir oil

$$M_b = \frac{(k_{rw})_{1-S_{hr}}}{\mu_w} \frac{\mu_h}{(k_{rh})_{S_{wi}}} \quad (\text{I.12})$$

Where:

$(k_{rw})_{1-S_{hr}}$ is the maximum relative permeability to water when $S_w=1 - S_{hr}$

$(k_{rh})_{S_{wi}}$ is the maximum relative permeability to hydrocarbons when $S_w=S_{wi}$

C. Geometrical skin: When a well only partially penetrates the pay zone or has limited perforations, flow lines converge, causing an additional pressure drop (positive skin). Perforation in tight formations is challenging due to high rock strength; if perforations do not penetrate beyond the damaged zone, flow efficiency is severely reduced. [25]

We can calculate the geometrical skin with the papatzacos equation :

$$S_c = \left(\frac{h}{h_p}\right) \ln\left(\frac{\pi h_p}{2}\right) + \frac{h}{h_p} \ln\left[\frac{\frac{h_p}{h}}{2 + \frac{h_p}{h}} \sqrt{\frac{(Z_p + 0.25h_p)(h - Z_p + 0.25h_p)}{(Z_p - 0.25h_p)(h - Z_p - 0.25h_p)}}\right] \quad (\text{I.13})$$

$$h_D = \frac{h}{r_w} \sqrt{\frac{k_h}{k_z}} \quad (\text{I.14})$$

Where:

Z_p indicates the distance of the center of the perforated interval from the reservoir bottom, k_h and k_z : are the horizontal and vertical effective permeability, respectively

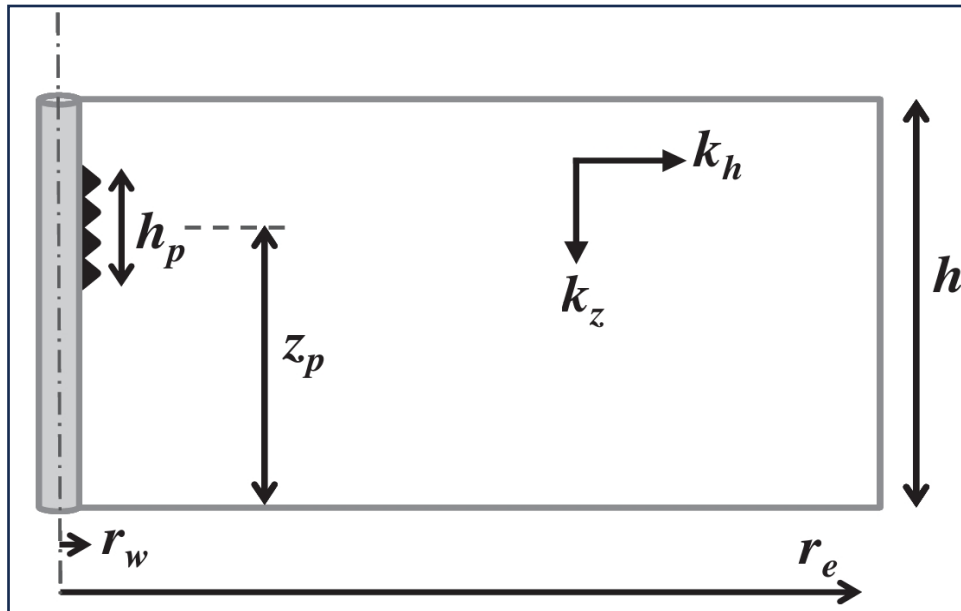


Figure I.10: Reservoir cross section with a partially perforate well [26]

2 | Chapter

Sand Control Techniques
and Integrity Management
Strategies

Introduction

Effective sand control requires the systematic integration of mechanical and chemical exclusion techniques with robust well integrity management frameworks. Mechanical methods range from standalone screens and cased-hole gravel packs to advanced frac-packing, each selected according to Saucier's sizing criteria and formation sorting. Chemical methods such as resin consolidation, provide remedial alternatives to reinforce incompetent matrixes while minimizing wellbore obstructions. These measures are governed by Well Integrity Management Systems (WIMS) utilizing the Two-Barrier Principle and real-time diagnostics like acoustic detectors and erosion probes.

II.1 Sand and silt control techniques

II.1.1 Restriction of production rate

One of the simplest and most cost-effective approaches. It consists of maintaining fluid production below the critical threshold beyond which the formation begins releasing sand uncontrollably. This threshold is determined through well-specific parameters fluid type, rock properties, flow rate, and pressure drawdown with the most reliable assessment being the "bean-up" test, where production is incrementally increased until sand breakthrough or the maximum acceptable rate is reached. This procedure also promotes natural cleaning of fines around the wellbore (Figure II.1).

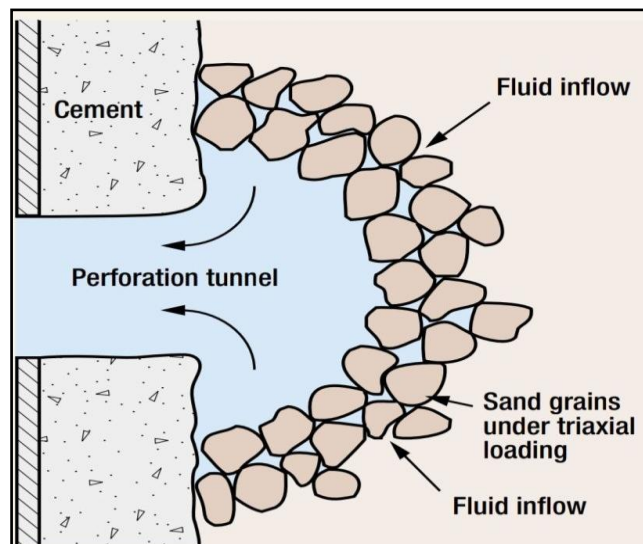


Figure II.1: Geometry of stable arch surrounding a perforation [27].

The technique relies on the formation of natural sand arches at pore throats under steady-state flow. These arches stabilize sand grains and prevent migration as long as velocity stays below a critical limit [2].

Stepwise rate increases cause temporary sand concentration spikes that gradually settle indicating arch re-establishment. Once the critical velocity is exceeded, arches collapse and sand production becomes continuous (Figure II.2), requiring an immediate rate reduction to restore formation stability [2].

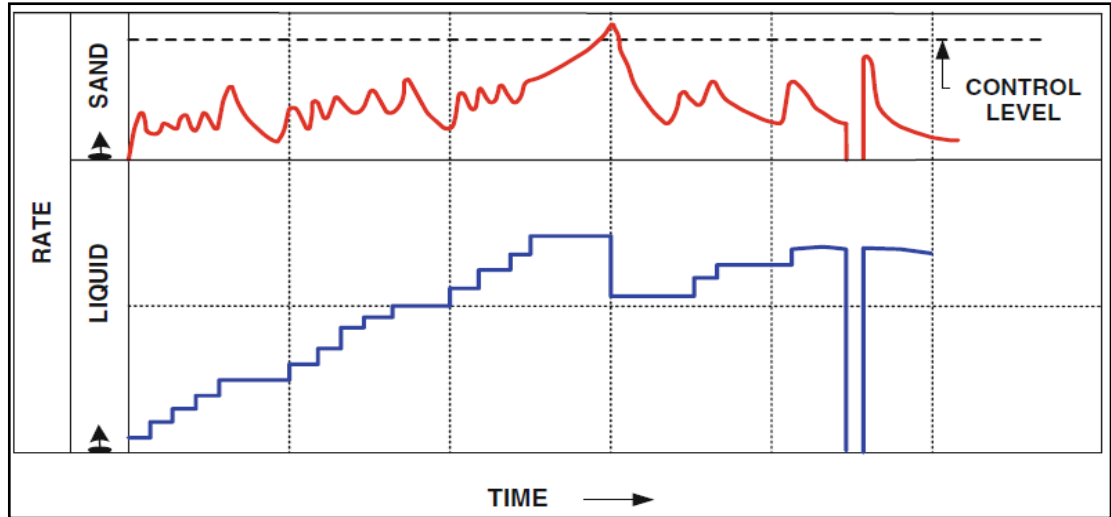


Figure II.2: Determination of sand production in accordance to flow rate [2].

II.1.2 Mechanical methods of sand control

II.1.2.1 Slotted liners

Slotted liners are a low-cost sand control completion system used to control formation sand production, primarily in horizontal wells drilled through unconsolidated, high-permeability sands producing high-viscosity oil. Their sand control mechanism is based on bridging, where sand grains bridge across the slots to form a stable arch, or they are used to restrain gravel in gravel-packed completions. When combined with gravel packing, slotted liners provide an additional sand filtering zone, improving overall sand management.

The slots on gravel packing liners are carefully manufactured at a workshop. They can be arranged and sized differently along the liner, either horizontally or perpendicularly.

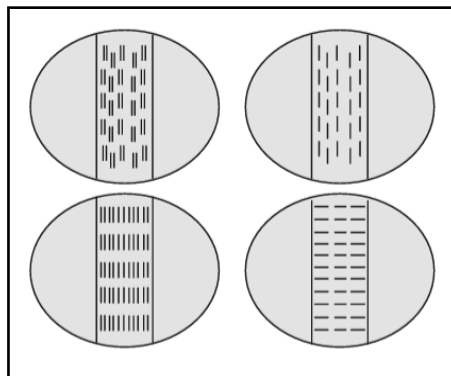


Figure II.3: Possible liner slot arrangements [2].

The flow area of the slotted liner determines how many slots there are. The overall area of the slots is often calculated as 2–3% of the liner's entire external surface area. The number of slots is calculated using this equation:

$$n_s = \frac{\alpha_s F_s}{w_s l_s} \quad (\text{II.1})$$

Where:

n_s : Number of slots per 1 m

α_s : total slot area of total external surface area of the liner

F_s : external surface area per meter

w_s : width of the slot

l_s : slot's length

Limitations

- Only effective in well-sorted, uniform formations.
- Plugging occurs rapidly in dirty or mixed-grain sands, shortening well life.
- Poor performance in long horizontal sections due to insufficient inflow rates.
- Generally reserved for low-economy wells, reflecting its limited reliability in complex reservoirs [2].

II.1.2.2 Expandable liners

Expandable slotted liners have been created to lower well expenses while increasing well productivity and decreasing sand production. Slot size based on deformation following expansion should be the primary consideration when employing such pipes (liner, casing, or screen) for sand control purposes.

Drill pipes or tubing are used to drop a slotted-expandable liner to the appropriate depth in the well. A cone that can be hydraulically extended to the required diameter is used for the expansion. By raising the cone to the top of the slotted pipe, expansion begins at the bottom of the slotted liner as shown in (Figure II.4.a). The cone can return to its smaller size when the pressure is released. This is due to the tubular joints' lack of slots and inability to expand. Depending on how many slotted pipes there are in the string, the procedure is repeated. If slotted-expanded pipes need to be retrieved, the enlarged slots should be collapsed back using the drill string and pulling power [2].

The width and wall thickness of steel strips between two slots are assumed to remain unchanged during deformation in order to compute the change in slot width (Figure II.4.b) Slotted width of the expanded liner is calculated with this equation:

$$w_e = \frac{2\pi}{m}(D_f - D_i) + w_s \quad (\text{II.2})$$

Where:

w_e : slot width on the expanded pipe

m : number of links between slots over the pipe cross section area

D_f : final (expanded) pipe outer diameter

D_i : initial outer diameter of the pipe

w_s : slot width before expansion.

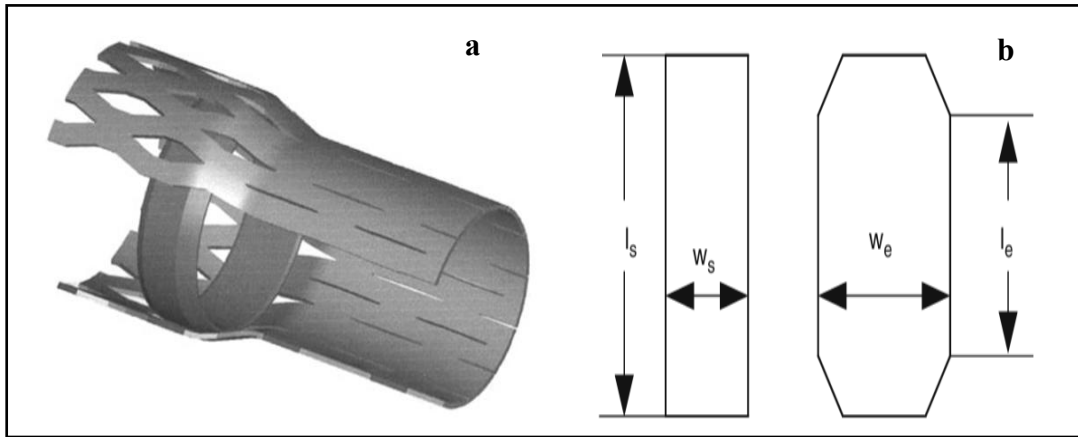


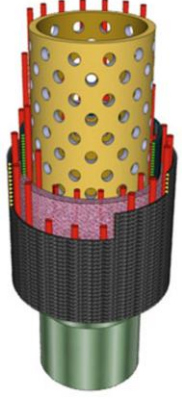
Figure II.4: a) Slotted pipe expansion, b) Slotted pipe before and after expansion [2].

II.1.2.3 Screens:

One of the main factors contributing to standalone screens wide application is their simplicity and relatively inexpensive installation cost. These completions include various screen kinds (wire wrapped, pre-packed, premium, expandable sand screens, etc.) described in (Table II.1). They are installed inside the open hole section without the gravel pack placement. Inflatable and swelling packers, which are acclaimed for their exceptional swelling and sealing abilities while completing additionally intervals, resolve zonal isolation inside open holes [19].

Table II.1: Different screen types [2].

Screen Type	Principle	Schematic
Wire wrapped screens	Wire wrapped screens consist of a perforated inner pipe wound with steel wire, offering a flow area and permeability that far exceed those of cased and perforated completions, thereby reducing fluid entry velocity at the screen face.	

Prepacked Screens	Prepacked screens consist of a wire-wrapped structure with gravel packed between inner and outer layers, available in single or double configurations, and are designed for use in open hole and cased hole completions, particularly in inclined wells requiring standalone or gravel pack applications.	
Special designed screens	Premium screens, available in wool-wrapped, metal, and chrome varieties, are designed for standalone applications, offering high permeability, mechanical integrity, and resistance to corrosion, erosion, and sour gases under high-temperature and high-pressure wellbore conditions.	

There is other types of screens:

- Through Tubing Small Diameter Screens
- Alternate Path Screens
- Expandable Screens

II.1.2.4 Gravel pack

Gravel pack is a sand control treatment whose primary objective is to establish an effective sand filtering zone allocated between the wellbore wall and the screen or slotted liner, retaining formation sand grains behind the completion and allowing sand-free fluid production. A wide array of different accessories and downhole tools is applied alongside several completion systems, including slotted liners, standalone screens, and common gravel pack installations.

A typical gravel pack placement procedure involves pumping a proppant-laden slurry down the annulus, where the gravel pack forms across the reamed reservoir while the carrier fluid enters the liner through the wash pipe and returns up the hole to surface. Old wells that produce sand can also be good candidates for such treatment, where a pressure pack of graded sand placed out beyond the casing effectively re-stresses and stabilizes the formation. Completion installations needed to apply such techniques should ensure safe treatment

execution concerning the treatment pressures induced during the operation, temperature profiles downhole, and the presence of sour gases such as H_2S and CO_2 , which necessitate proper material grade selection and sour gas resistivity. Furthermore, pressure and temperature changes cause occurrence of ballooning, piston, buckling, and thermal effects, all of which reflect significant change in tubular length. Well deviation, treatment fluid type are also matters of concern to ensure successful operation performance [2]. The following picture (Figure II.5) represent gravel pack installation methodes:

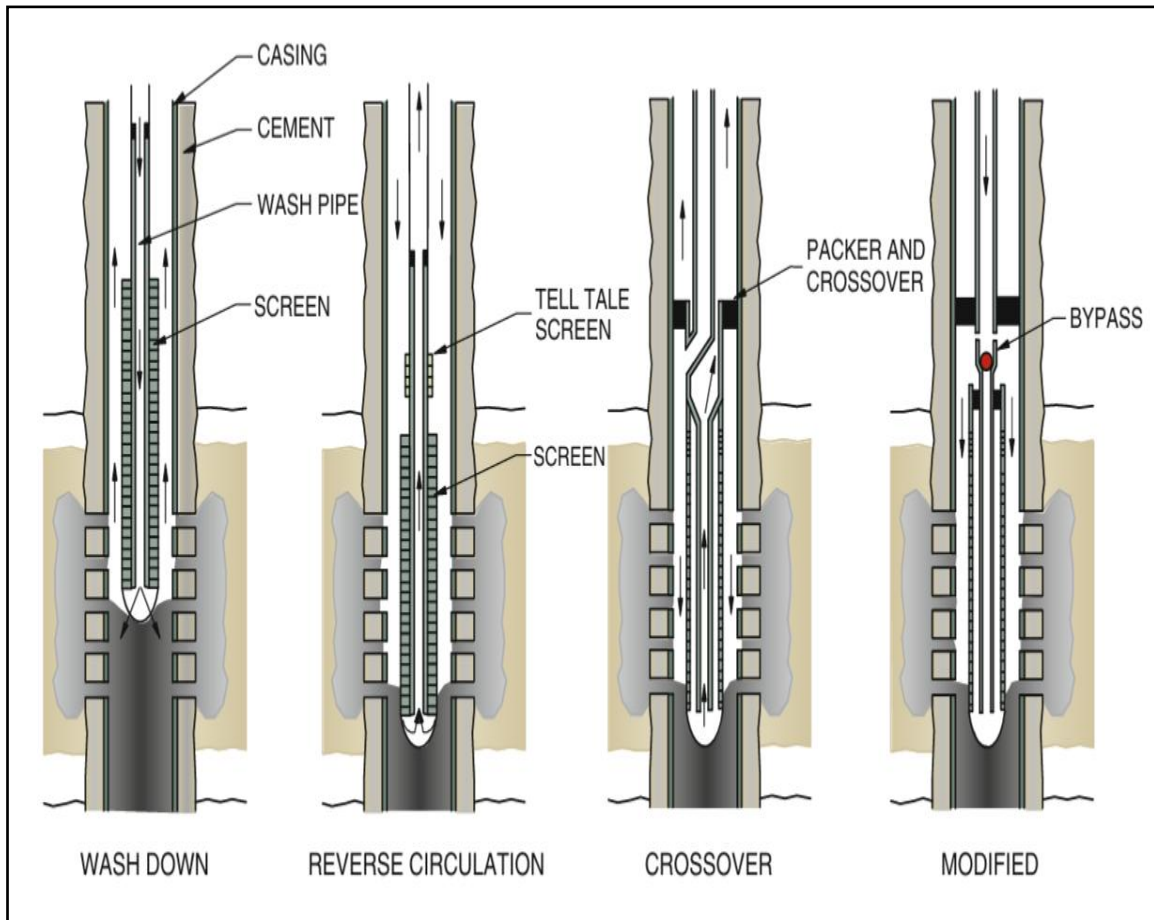


Figure II.5: Different gravel pack installation methodes [2].

II.1.2.5 Frack pack

The popularity of fracture stimulation combined with sand control as a completion technique has intensified in recent years. Due to the pronounced success of frac packing, this technique has become the preferred completion method in sand control environments [28].

Traditional methods suffer limitation that 50% of the productivity index (PI) can be lost within the first year due to fines migration [29]. Consequently, frac-packing has emerged as the definitive solution for high-rate wells in permeable environments [30].

The most obvious economic justification for frac-pack completions is improved completion efficiency (lower skin) and the resultant higher flow rates. (Figure II.6)

Frac-packs have a much lower average skin value than gravel packed completions (+0.4 versus +21) [28].

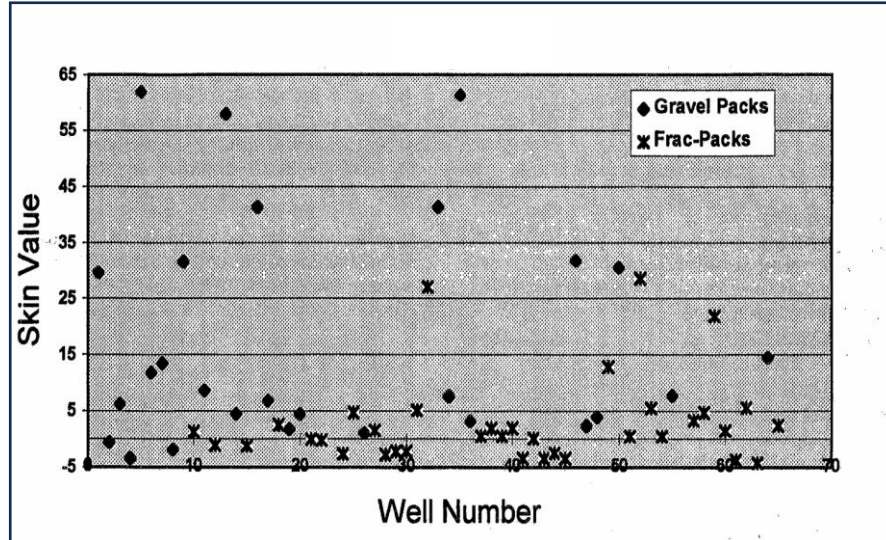


Figure II.6: The variation of the skin in sand control methods [28].

A. Principle of frack pack: The basic idea behind a frac-pack is to optimize the reservoir contact area and avoid near-wellbore damage, it improves the effective wellbore radius efficiently, which results in a large decrease in drawdown pressure. By employing a Tip Screen-Out (TSO) design to create a short, wide, and highly conductive fracture. The fluid velocity at the formation-proppant interface is kept below the critical threshold necessary to initiate fines migration by this enhanced surface area for fluid entry. As a result, this process keeps the proppant pack from clogging and guarantees long-term production [29].

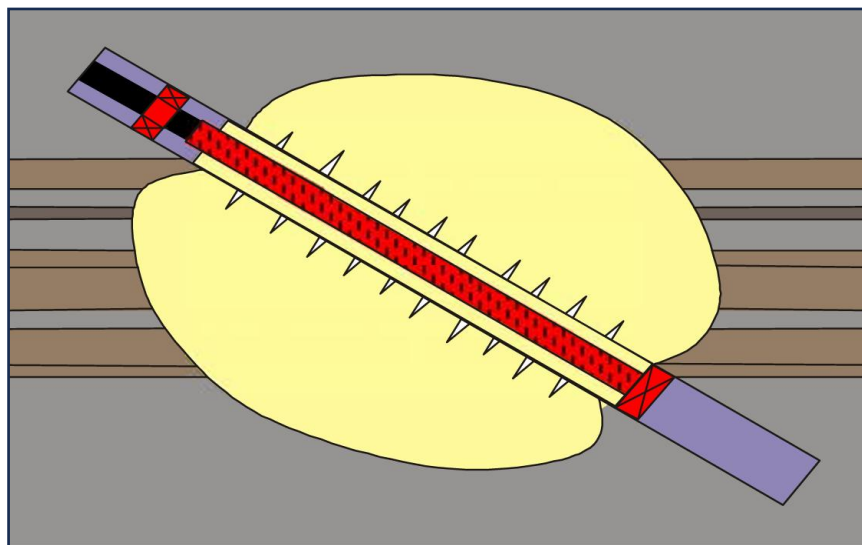


Figure II.7: Frack pack (TSO design) [31].

B. Comparison between FP and GP

The (Table II.2) represents the difference between gravel pack and frac pack

Table II.2: Case history [28].

	Frac pack	Gravel pack	Difference
Rig time (days)	1.5	1.5	None
Cleanup (days)	0.7	2	-1.3
BODP	1431	379	1052
MCFD	559	121	438
FTP (psi)	1610	1560	50
BHP (psi)	3582	3655	-73
Perforation(in)	62	50	12
Invoice (\$)	99800	53600	46200

There is different types of mechanical methodes including:

- Alternative path gravel pack;
- Alpha Beta pack;
- High rate water pack;
- Acid pre-pack.

II.1.3 Chemical consolidation:

In unconsolidated formations where grain-to-grain forces are insufficient to maintain the formation strength, chemical sand control is based on the in situ chemical consolidation of sand with agents. The primary goal is to consolidate sand grains together as shown in (Figure II.8) to form a mass with improved compressive strength without causing damage to the reservoir [2].

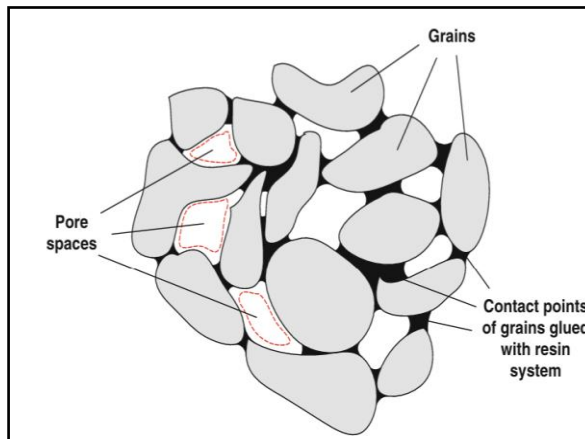


Figure II.8: Grains contact points after the resin consolidation treatment [2].

II.1.3.1 Resins

Resins are solid, hard to soft, organic, non-crystalline polymers with a brittle solid state. The resin polymer network has an extremely narrow molecular mass distribution. Because resins are flammable. Thermosetting and thermoplastic resins are the two categories of resins.

- **Thermosetting Resins:** Thermosetting resins are low molecular weight substances that, then heated, permanently change from fusible and soluble to infusible and insoluble via a network of cross-linked polymers. After curing, polymer chains unite into a single molecule, creating a solid mass between sand grains that is strong, hard, and resilient enough to bear extreme strains while staying chemically inert to rocks and wellbore fluids and stable throughout a broad temperature range [2].

The most utilized types of thermosetting resins are:

- Phenol resins,
 - Furan resins,
 - Amino resins,
 - Epoxy resins,
 - Unsaturated polyester resins,
 - Urethane foams,
 - Alkyl resins.
- **Thermoplastic Resins** Thermoplastic resins, in contrast to thermosetting ones, are reversible, which means that their physical state may be altered by varying the temperature and pressure. High molecular weight (>10,000) coupled monomers make up thermoplastic polymers. Heating or dissolving the material may readily break molecular bonds [2].

Thermoplastic resins include:

- Polyethylene,
- Polypropylene,
- Polystyrene,
- Polyvinyl chloride,
- Furan resins.

Furan resins can be fabricated to be thermosetting or thermoplastic.

II.1.3.2 Treatment Execution

Resin consolidation treatment needs expert supervision to ensure safe and technically accurate performance. The treatment covers a near-wellbore zone of up to 1.5 m thickness, with thin layers of less than 6.0 m being advised, and a maximum treatable zone of 7 m in

one step. Based on sand production predictions, the treatment should preferably target zones that have never produced sand before. Following steps of treatment execution:

- Clean perforation tunnels with HCL-HF mud acid to eliminate undesirable particles.
- PreFlush operation is thus carried out with the primary goal of eliminating reservoir fluids, especially water, which is incompatible with the resin system and capable of contaminating it.
- Formation temperature is an important element in treatment fluid preparation since it determines resin hardening time and the quantities of additives like accelerators and curing agents. To guarantee uniform formation coverage, injection must take place below fracture initiation pressure and at low rates.
- OverFlush or displacement fluid is used to displace all except residual resin saturation at grain contact locations. [2]

The figure (Figure II.9) describes the treatment execution:

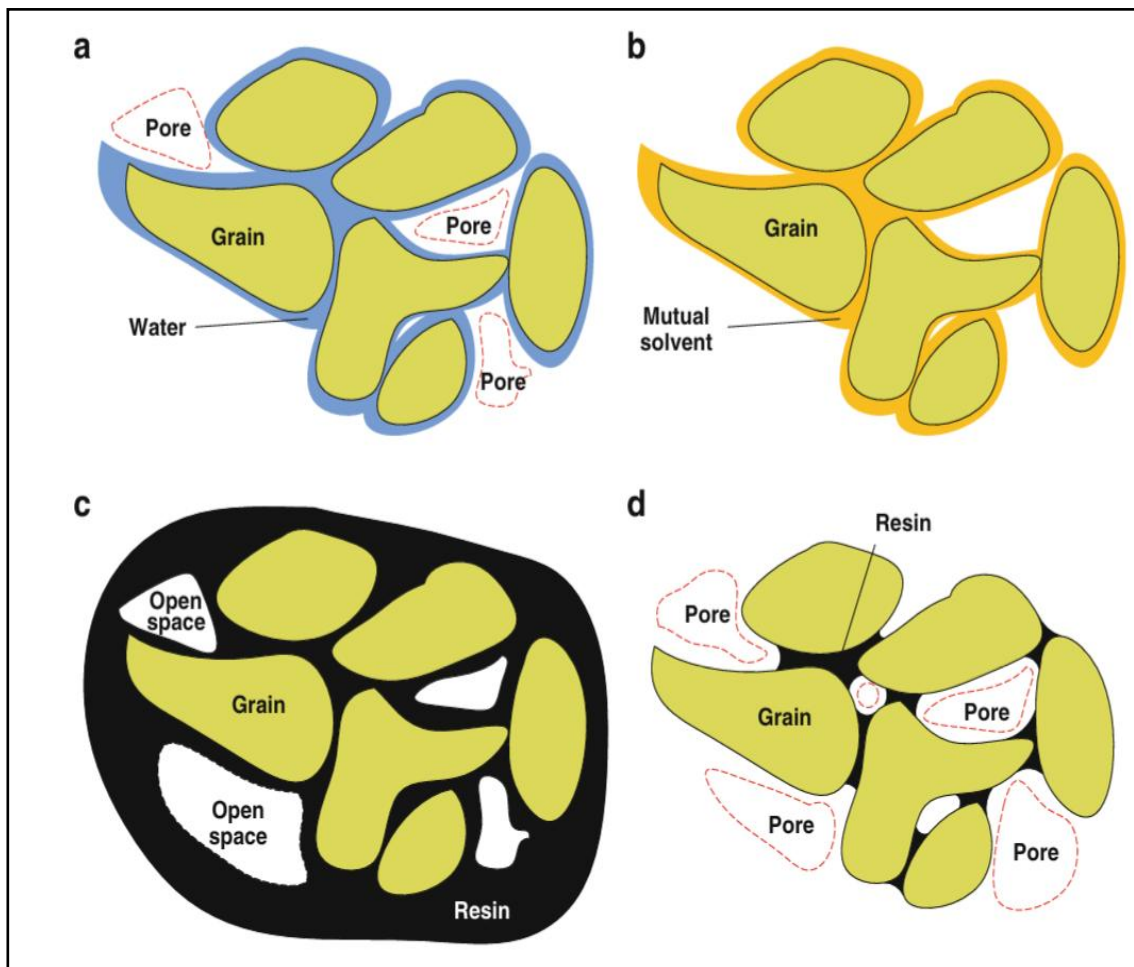


Figure II.9: Chemical sand consolidation sequences [2].

II.1.3.3 Additives:

Desired treatment fluids in chemical consolidation are not usually ready to use without additions since they help achieve the necessary properties for proper placement, resin curing, and other operations, the (Table II.3) defines the role of each additive:

Table II.3: Different additives and their role [2].

Additive	Use	Role
Activators	Main treatment, Overflush	prolong resin placement time and minimize curing time
Accelerators	Overflush	reduce treatment placement time
Surfactants	Preflush	lower the surface tension between two liquids or liquid and solid
Isopropyl alcohol	Preflush	Flammable, intoxic, evaporates quickly, able to dissolve a wide range of compounds
EGBME	Preflush	solvent with solvency for both aqueous and non-aqueous liquids, effectively cleaning sand and miscibly displacing residual water, resulting in better accessibility of resin to intergranular spaces.

II.1.4 Combined method

Resin-coated gravel treatments can be pumped in the well in two different ways. The first method uses dry, partially catalyzed phenolic resin-coated gravel. A thin layer of resin (approximately 5% of the total sand weight) is pumped into the well to completely fill the casing and perforations. When the resin is exposed to bottom hole temperature or injected steam, it cures into a consolidated pack that functions as a permeable filter to stop the production of formation sand. This method is primarily used in prepacked screens.

In the second method, which employs wet resins like epoxies or furans, the well is prepacked with gravel, the resin is pumped and catalyzed to solidify, and the consolidated plastic-sand combination is drilled out of the well after curing, leaving resin-coated sand in the perforations as a sand control barrier [32].

(Figure II.10) depicts a comparison of grain interaction between uncoated and resin-coated proppant, illustrating how resin-coated proppant packs effectively distribute stress over a greater area at grain contact points, resulting in higher breaking resistance of detached grains and reduced embedding into the formation. This property makes resin-coated proppant

particularly effective in frac packing operations, where it prevents sand influx at extremely high fracture closing pressures while maintaining pack integrity and conductivity [2].

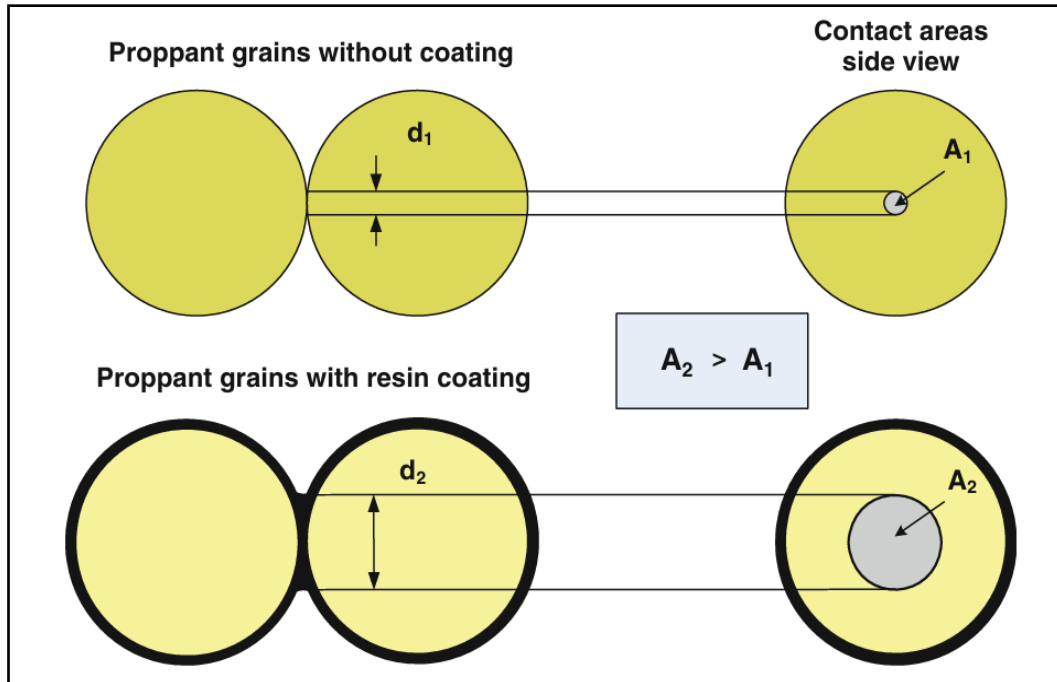


Figure II.10: Comparison of proppant grains with and without resin coating [2].

II.2 Design criteria for sand control selection

II.2.1 Formation sampling and sand analysis

Formation sampling is the most important phase in sand control design since the reliability of future analysis is directly proportional to the quality and relevance of the obtained samples. The representative samples are obtained by coring the entire length of the interval with adequate coring equipment, using double-tube core barrels or those with rubber sleeves, and side coring equipment, although the use of bailed or produced sand samples leads to errors and problems and is the poorest kind of data [2].

A sieve analysis is a laboratory procedure used to choose the appropriate-sized gravel-pack sand from a sample of formation sand. A formation sample is placed at the top of a stack of screens with successively decreasing mesh sizes in order to perform a sieve analysis. The sand grains in the sample will fall down the screens when the sieve stack is placed in a vibrating machine until they come across a screen with too tiny apertures for some grain sizes.

The weight of the formation sample retained by each size screen can be calculated by weighing the screens before and after sieving. The cumulative weight percent of each sample retained can be plotted as a comparison of screen mesh size on semi-log coordinates to obtain

a sand size distribution plot, as shown in (Figure II.11). The median formation grain size diameter, also known as d₅₀, is the basis for gravel-pack sand size-selection procedures [32].

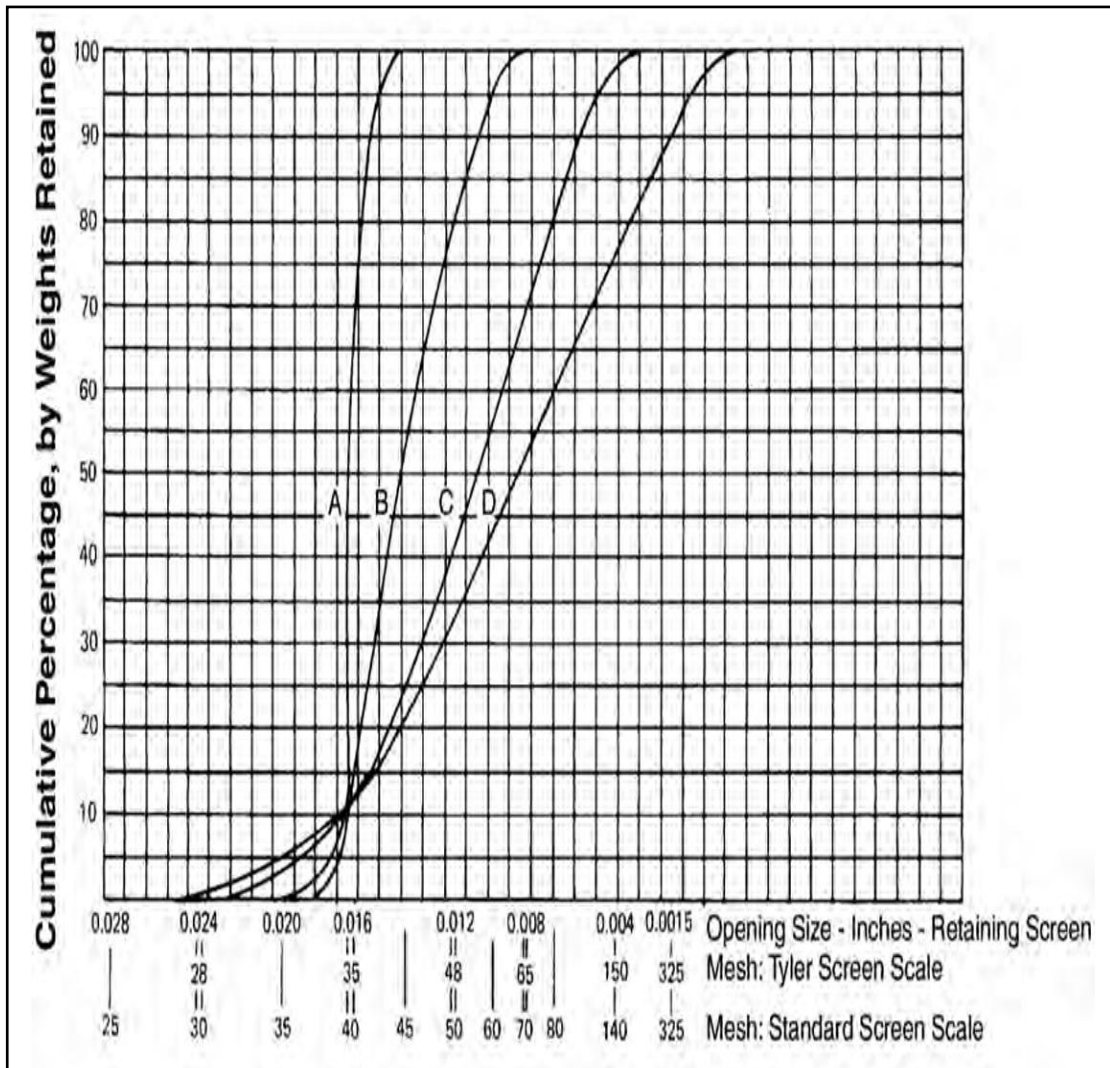


Figure II.11: Sand size distribution plot from sieve analysis [32].

The (Table II.4) describes different mech size with their appropreate seive opening:

Table II.4: Standard sieve openings [32].

Mesh size	Sieve opening [in]	Sieve opening [mm]	Mesh size	Sieve opening [in]	Sieve opening [mm]
2.5	0.315	8.00	35	0.0197	0.500
3	0.265	6.730	40	0.0165	0.420
3.5	0.223	5.660	45	0.0138	0.351

4	0.187	4.760	50	0.0117	0.297
5	0.157	4.000	60	0.0098	0.250
6	0.132	3.360	70	0.0083	0.210
7	0.111	2.830	80	0.0070	0.177
8	0.0937	2.380	100	0.0059	0.149
10	0.0787	2.000	120	0.0049	0.124
12	0.0661	1.680	140	0.0041	0.104
14	0.0555	1.410	170	0.0035	0.088
16	0.0469	1.190	200	0.0029	0.074
18	0.0394	1.000	230	0.0024	0.062
20	0.0331	0.840	270	0.0021	0.053
25	0.0280	0.710	325	0.0017	0.044
30	0.0232	0.589	400	0.0015	0.037

When it comes to proppant selection, the gravel-packing origins of frac and-pack are clear, just as they are with equipment and fluids. Engineers first concentrated on sand exclusion and gravel pack-based size criteria (Figure II.12). In 1974 Saucier suggests that the average gravel size d_{g50} be five to six times the average formation grain size d_{f50} . The so-called "4-by-8 rule" reflects the minimum and maximum grain-size diameters dispersed around Saucier's criterion [2].

LPS analysis is more representative of tiny particles (down to 0.1 mm), requires a smaller sample (1 g), is cost-effective, and rapid. The approach is based on a hypothesis that describes the intensity of light dispersed by colloidal particles. Using assumptions about particle adsorption and refractive index, the detector calculates the particle volume and converts it to diameter, assuming the particle is a sphere [2].

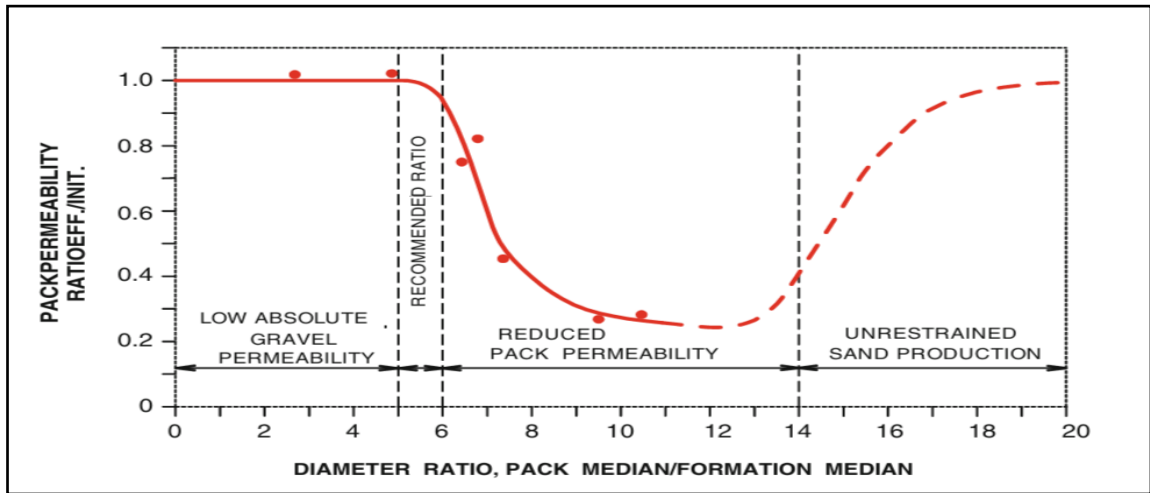


Figure II.12: Effect of the ratio of medium gravel size to medium sand size on gravel pack permeability [2].

II.2.2 Screen design and selection

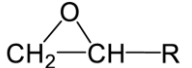
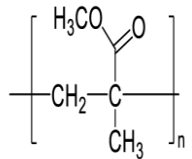
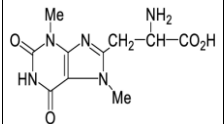
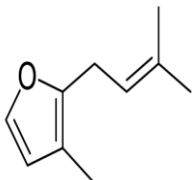
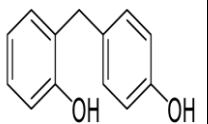
The mechanism of sand production exclusion of wire-wrapped screens and slotted liners is to exclude larger particles from entering the wellbore by controlling seam width, where a sand bridge will be formed by larger particles outside the screen to achieve sand production exclusion, making seam width the major design parameter for sand production excluding screens [13]. additionally, screen section length depends on perforated interval length and should extend 1.5–2.0 m above and below perforations, while screen type selection depends on operator practice and downhole conditions, with premium or special design screens made of high grade alloys and chrome resistant to corrosion used in HP/HT environments with H₂S occurrence, whereas cheaper versions such as wire wrapped screens are installed when downhole conditions are not aggressive [2].

II.2.3 chemical products design and selection

The main design criteria for chemical sand control treatments must address several critical parameters. Permeability reduction in the near wellbore region represents the primary concern, as injecting chemicals into the porous medium decreases the permeability of the area around the well due to the reduction in the size of the pores. Closely related to this, capillary force increase must be considered in the placement design. The injection rate and chemical concentration must therefore be optimized to ensure uniform distribution and adequate penetration depth without excessive pore size reduction. Furthermore, the selected chemical must demonstrate sufficient temperature resistance to maintain its consolidation properties and structural integrity under downhole conditions without degradation. Finally, acid resistance of the consolidated mass is equally critical, as the treated formation may be

exposed to acidic environments requiring the chemical to preserve its mechanical strength under such aggressive conditions [33].

Table II.5: Commonly used sand control materials [34].

polymer	Heat resistant	strength	advantage	disadvantage	Chemical structure
Epoxy resin	exelent	good	High strength	Easy to break	
Polymethyl methacrylate	moderate	good	Light weight and easy to prosess	Poor temperature resistance	
polyurethane	moderate	good	High fracture toughness	No resistente to acid and alkali	
Furan resin	moderate	poor	Chemical corosion resistance	The curing prosess is complex	
Phenolic resin	Excelent	good	Good thermal stability	Poor fracturing toughness	

II.3 Evaluation of the efficiency of sand control

II.3.1 Productivity index and flow efficiency metrics

The primary indicator of sand control efficiency from a production perspective is the preservation of the Productivity Index (J or PI) and the minimization of the Skin Factor [27].

II.3.1.1 Flow efficiency

This represents the relative percentage of the theoretical flow rate achievable through the formation. For example, a well with a skin of +20 is estimated to have a flow efficiency of only 28%.

Flow efficiency can be calculated using this equation:

$$FE= 100 \left(\frac{q_s}{q_o} \right) = 100 \left[\frac{\ln\left(\frac{r_e}{r_w}\right)}{s + \ln\left(\frac{r_e}{r_w}\right)} \right] \cong 100 \left(\frac{8}{s + 8} \right) \quad (II.3)$$

Where:

FE = flow efficiency (%)

q_s = flow rate from damaged well (STB/d)

q_0 = hypothetical flow rate from undamaged well (STB/d)

r_e = drainage radius of well (ft) s_{fl}

r_w = wellbore radius (ft)

S = productivity skin factor

II.3.1.2 Completion-Induced Skin:

Mechanical methods like gravel packing can result in a loss of productivity compared to open-hole completions due to flow convergence at the perforations. However, successful gravel packs can stimulate productivity and yield negative skin factors in open-hole environments by replacing damaged formation sand with high-permeability gravel [27].

II.3.1.3 Gravel pack evaluation:

There are several logging services and evaluation approaches available for assessing material placement in gravel packs, as shown in (Figure II.13).

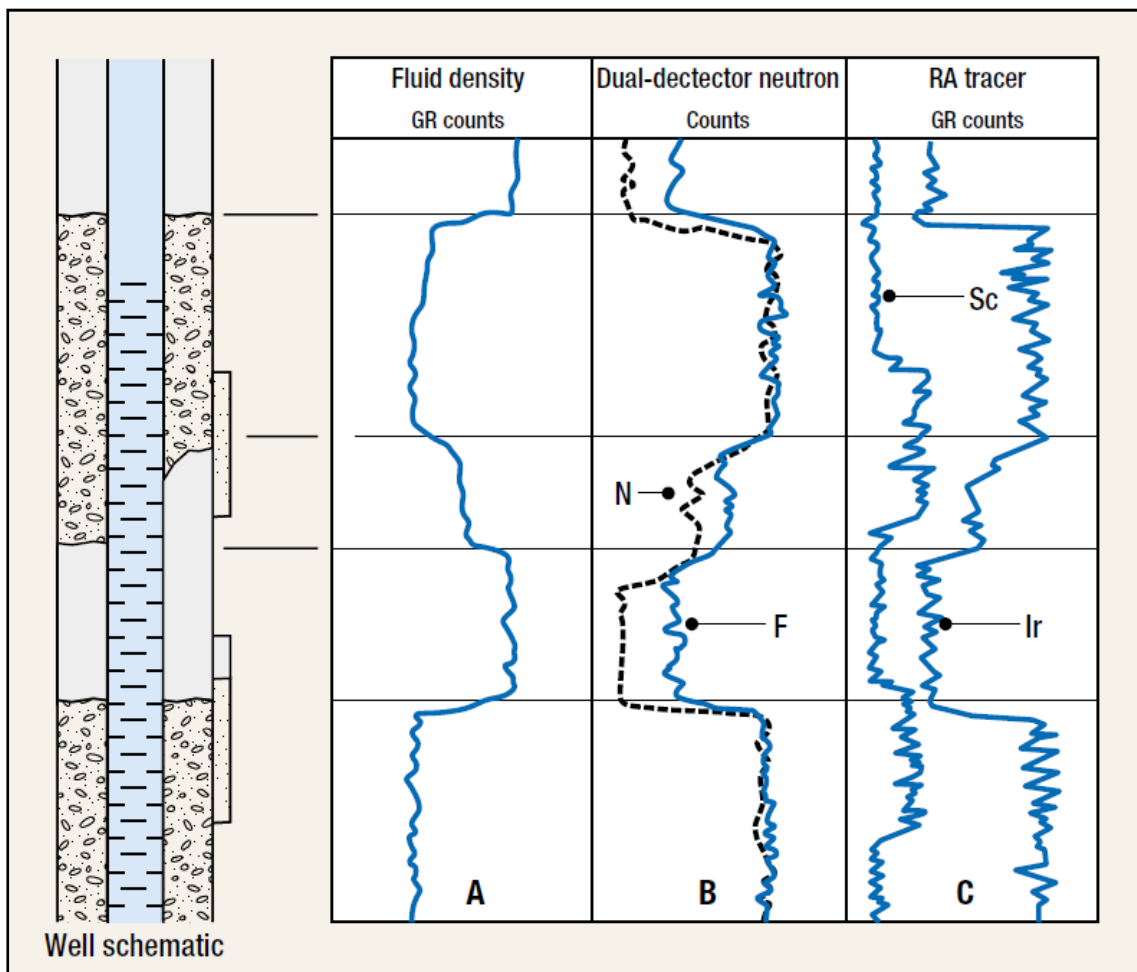


Figure II.13: Gravel Pack log evaluation [27].

Where:

- Density log: a full bore detector detects gamma rays from a tool-mounted radioactive (RA) source.
- Dual-Detector Neutron Log: variations in the count rate of neutrons released by a tool-mounted RA source indicate variations in the hydrogen index.
- Spectral Gamma Ray "tracer" log: In a single logging job, spectral gamma readings can assist detect numerous RA isotopes linked to pumped materials [27].

II.3.1.4 Chemical impairment

Chemical sand consolidation (SCON) using resins often causes a sharp decrease in permeability, in some cases up to 60% [35]. However, this permeability alteration is usually limited to a radius of 3 to 5 feet, and the resulting skin factor is typically less than 5 [36].

II.3.1.5 Frac-pack performance

This technique typically results in production increases 2.0 to 2.5 times higher than comparable gravel packs [2]. Frac-packing is highly efficient in bypassing near-wellbore damage and connecting laminated sand/shale sequences, often yielding negative skin factors down to -3 [27].

II.3.2 Operational and economic longevity

The longevity of the treatment defines its field-scale efficiency.

II.3.2.1 Success definitions

In a field perspective, an operation is considered successful if production remains sand-free for approximately three years. It is partially successful if sand-free for nine months, and unsuccessful if failure occurs in less than six months [35].

II.3.2.2 Erosion risk (C-factor)

To evaluate the risk of erosion failure in screens and slotted liners, a "C-factor" empirical constant is used. Data suggests that erosion failure frequently occurs below a C-factor of 60, which serves as a safe operating limit for sand control completions [2].

The following equation determines the velocity of the fluid flow above which erosion may occur:

$$C = v_p \times \rho_m^{0.5} \quad (\text{II.4})$$

Where:

C = empirical constant

v_p = fluid velocity (ft/s)

ρ_m = mixture density (lbs_m / ft^3)

II.3.2.3 Failure rates

In Malaysian mature fields, the overall success rate for SCON was 75%, while sand agglomeration treatments showed a 66% success rate (Figure II.14) [36].

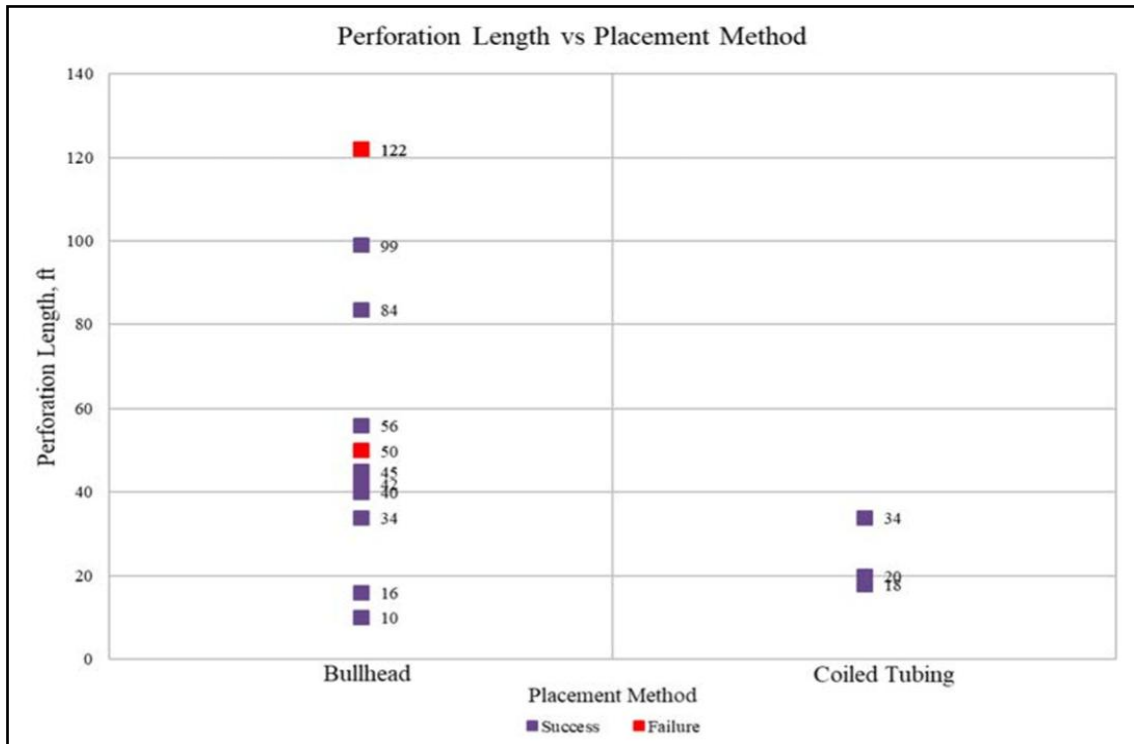


Figure II.14: Comparison between bullhead and coiled tubing placement method for all chemical SCON and sand agglomeration job with different perforation length [36].

II.4 Well integrity monitoring and mitigation measures

Well integrity monitoring in sand-affected wells is a multi-dimensional surveillance process designed to detect solids production, localize ingress points, and assess structural degradation of well barriers. Because sand production acts as a primary driver for mechanical degradation including erosion, material loss, and casing collapse operators utilize a combination of real-time sensing, surface detection, and periodic diagnostic logging [17].

II.4.1 Real-Time distributed sensing

Modern surveillance leverages fiber-optic (FO) technology to provide continuous, non-invasive monitoring along the entire length of the wellbore.

II.4.1.1 Distributed Acoustic Sensing

This technology records vibrations and strain patterns caused by sand particles impinging on the pipe wall. It allows operators to pinpoint the exact location of sand entry (ingress zones) across completion intervals in real-time. Case studies from the ACG field

demonstrated that DAS can effectively distinguish sand "signals" from background "noise," enabling targeted remediation with expandable patches [37].

II.4.1.2 Distributed Temperature Sensing

DTS identifies temperature anomalies associated with fluid flow. Notably, sand production has a cooling impact that lowers the local temperature when it mixes with the fluid stream, allowing DTS to characterize the intensity and location of solids generation [37].

(Figure II.15) represents DAS and DTS data collection from the well:

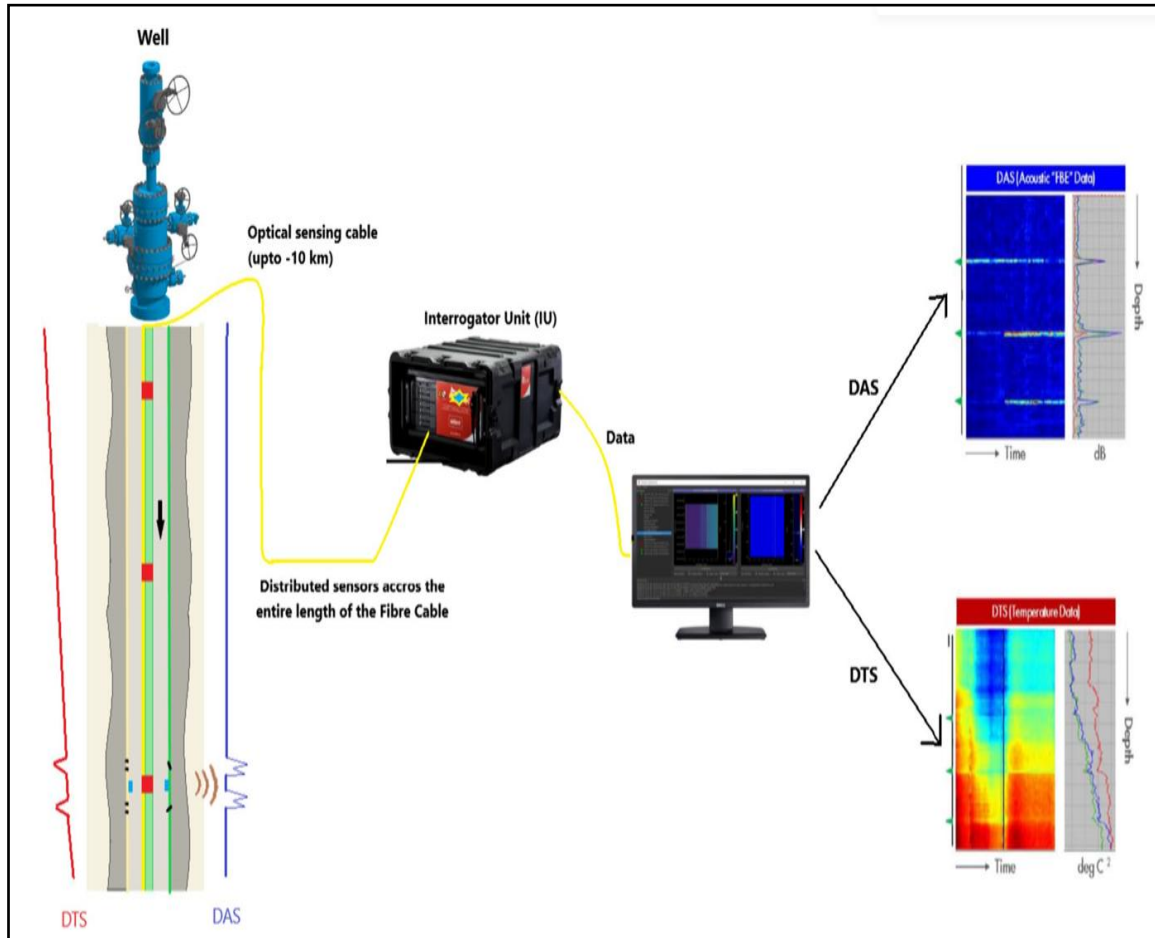


Figure II.15: Schematic description of FO data acquisition and processing [37].

II.4.2 Surface and intrusive monitoring tools

Surface tools provide immediate detection of solids before they cause catastrophic erosion of surface safety-critical elements (SCEs).

II.4.2.1 Acoustic sand detectors

Acoustic-based non-intrusive sand monitoring sensors, also known as Acoustic Sand Detectors, detect the sound produced by sand particles as they contact the inner pipe wall (Figure II.16), allowing operators to determine the Maximum Sand-Free Rate (MSFR). The sensor is affixed to the outside of the pipe, usually downstream of a 90° curve. Due to inertia,

the sand particles conveyed by the process medium crash with the inner pipe wall immediately following the bend. These collisions produce sound, which is caught by the microphone located on the tip of the sand monitor. The noise created increases with both velocity and sand concentration in the process medium. Because this gadget monitors sound, it can respond quickly to variations in sand output [38].

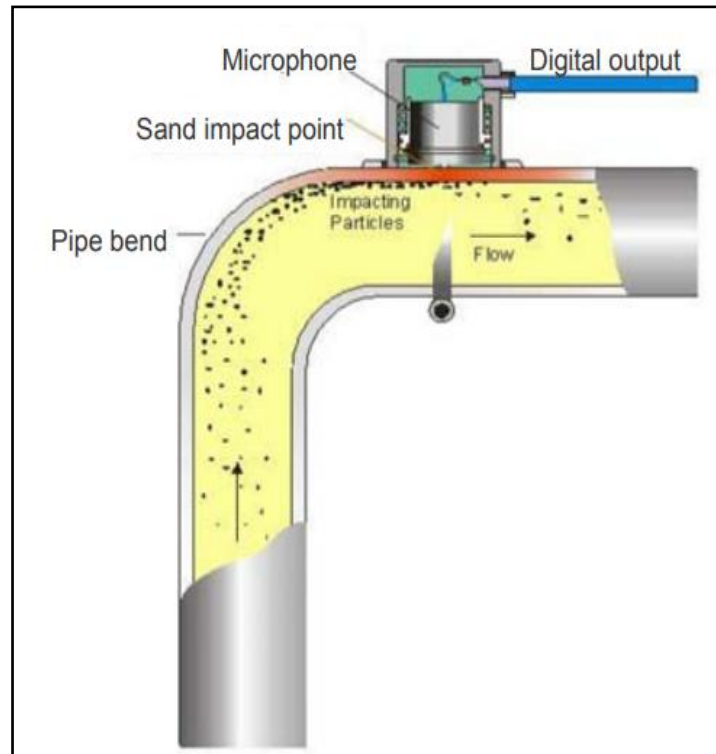


Figure II.16: Acoustic Sand Detectors [38].

Field evidence from the Bonga Field suggests that ASDs are critical because surface "sand cut" samples often provide no early warning of downhole failure [39].

II.4.3 Periodic diagnostic logging

When monitoring identifies integrity anomalies, specialized logs are deployed to quantify structural damage and metal loss.

II.4.3.1 Multi-finger caliper logs

These are used to identify internal casing deformation, ovality, and wall thickness loss caused by the abrasive action of sand flow or mechanical wear.

II.4.3.2 Electromagnetic and ultrasonic imaging

High-resolution tools map the casing-cement interface and inspect components like Subsurface Safety Valves (SSV) for sand-induced fouling or metal loss.

II.4.3.3 Spectral noise logging

This method detects leaks or crossflows behind the casing that may be caused by sand-induced channels or compromised cement sheaths [17].

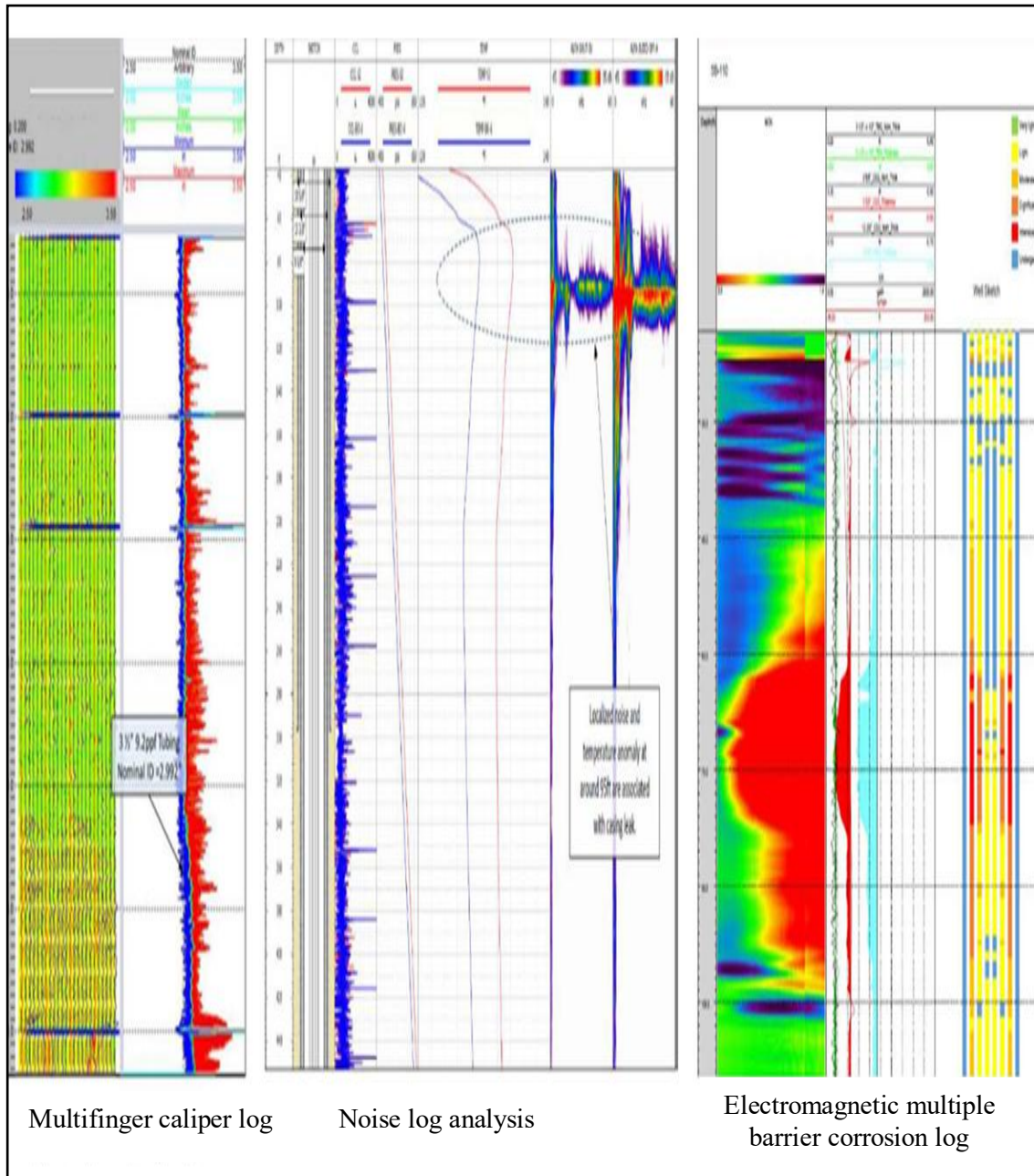


Figure II.17: Advanced well integrity diagnostics using logging technologies [17].

II.4.4 Systematic integrity management

Well integrity management system (WIMS) describes the procedures of well lifecycle management from design to abandonment, well integrity is managed through two main categories:

- Design integrity: which identifies the technical requirements and operational limits for the well equipments during well design phase.
- Operating integrity: which identifies the standards and operating limits of the equipments during operations.

Well failure model (Table II.6) ‘WFM’, defines the reasons and effects of well failure types on one matrix and provide optimal strategy to maintain technical integrity, also it consist of codes and rules to be followed:

Table II.6: Well failure model [39].

Well failure model					
Failure mode code		Well type			
		Natural flow	Gas lift	Subsea natural flow	Subsea water injector
	Well failure model code	NF	GL	SN	SI
	WIT required	Y	Y	Y	Y
	SIT required	Y	Y	Y	Y
Singel surface failure					
SSF1	SSSV failure	3	3	4	4
Multiple surface failures					
MSF1	SCSSV	9	9	5	5
Single sub-surface failure					
SSSF 5	Integrity failure – completion leak below downhole safety valve	9	9	8	
SSSF 6	Integrity failure – leak across production casing, see note D	8	8	8	8
Multiple sub - surface failures					
MSSF 1	Integrity failure completion & production casing, see note D	9	9	9	9
Mitigating action matrix – key to numbers entred in matrix above					
Resulting well traffic light	Action code	Required actions			
	0	No faults, well tested within operating parameters			
	1	Repair at next planned maintenance / intervention			
	2	Repair at earliest opportunity but within 24 months - the well can be flowed during this grace period			

	3	Repair at earliest opportunity but within 12 months - the well can be flowed during this grace period
	4	Repair at earliest opportunity but within 6 months - the well can be flowed during this grace period
	8	Carry out formal technical review within 7 days to determine mitigating actions and when/how to repair
	9	Make well safe immediately and repair / test / suspension / abandonment. Make well safe may be carried out by repairing defect at initial visit to well
Guidance Notes & Definitions		
C	Where subsea annuli monitoring capabilities are lost -a Formal Risk Assessment takes place with attendees being, but not limited to, Well Integrity TA, Lead PT, installation PT, Operations Rep and Subsea Main Engineer. For subsea wells with suspected trapped B annulus pressure problems where annuli monitoring capabilities are essential for maintaining minimum annulus pressures, the action code shall be designated as 9.	
D	Whenever a well develops a hydrocarbon leak into an annulus a Formal Risk Assessment shall take place with attendees including, but not limited to, Well Integrity TA, Lead PT, installation PT, production programming or Analyst Operation to take total risk from location hydrocarbon inventory into account as per installation gas lift ALARP guidelines.	

Effective monitoring is integrated into a Well Integrity Management System to maintain the well within its safe Operating Envelope.

II.4.4.1 Deviation Management

Deviation management is grounded in a multi-disciplinary risk assessment process that identifies risks and defines appropriate mitigation measures. Wells deviating from integrity standards such as overdue assurance tests or failed safety-critical equipment may be granted a formal well integrity deviation, deferring assurance activities due to the limited intervention accessibility characteristic of deepwater environments. All deviations require approval from relevant technical authorities, with compliance tracked through monthly key performance indicators.

The following (Table II.7) defines risk matrix:

Table II.7: The risk assessment matrix [39].

severity	Consequences				Increasing likelihood				
	people	Assets	Enviroment	Reputation	A	B	C	D	E
					Never heard of in the industry	Heard of in the industry	Has happened in the organisation or more than once per year in the industry	Has happened at the location or more than once per year in the organisation	Has happened more than once per year at the location
0	No injury or health effect	No damage	No effect	No impact					
1	Slight injury or health effect	Slight damage	Slight effect	Slight impact					
2	Minor injury or health effect	Minor damage	Minor effect	Minor impact					
3	Major injury or health effect	Moderate damage	Moderate effect	Moderate impact					
4	PTD or up to 3 fatalities	Major damage	Major effect	Major impact					

5	More than 3 fatalities	Massive damage	Massive effect	Massive impact					
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II.4.4.2 Annulus pressure monitoring

Continuous tracking of A, B, and C annuli is essential for identifying Sustained Casing Pressure (SCP), which often signals a breach in a downhole barrier (e.g., casing leak or cement failure) exacerbated by sand production.

II.4.4.3 Well operating envelopes

Operators define standardized criteria for maximum drawdown and fluid velocities across screens. Monitoring ensures these limits are not exceeded, thereby minimizing erosion rates [39].

II.4.5 Integration of machine learning and artificial intelligence in well integrity monitoring

The industry is transitioning toward Smart Monitoring, using Machine Learning (ML) to process the vast data volumes (up to 1 TB/day) generated by DAS and DTS [37].

II.4.5.1 Acoustic fingerprinting

Machine Learning algorithms are trained on "acoustic fingerprints" of sand ingress to differentiate between stable production and discontinuous sand events [37].

II.4.5.2 Predictive maintenance

By integrating real-time sensor data with physics-based models (Digital Twins), operators can predict the Remaining Useful Life (RUL) of components subject to erosion and optimize maintenance schedules before a failure occurs [17].



General Conclusion

General Conclusion

This work, entitled Assessment of silte control techniques and wellbore integrity in damaged producing horizons: a case study of the Hassi Berkine field, investigates the problem of sand production and its consequences on well integrity in oil and gas wells of the Berkine Basin, with a particular focus on the El Merk field, aiming to provide both a theoretical understanding of the phenomenon and a practical overview of the methods used to control and manage it.

The first chapter established the fundamental mechanisms governing sand and silt production, examining the geological and reservoir factors that contribute to formation failure and its consequences on wellbore integrity. Building on this foundation, the second chapter explored the main sand control techniques available to engineers, ranging from chemical consolidation and gravel packing to frac pack completions, along with the criteria governing their selection and application. The analysis highlighted that no single method is universally applicable, and that an informed choice must account for well conditions, reservoir properties, and economic constraints.

The field study focused on two candidate wells, Well 1 and Well 2 selected on the basis of well test data showing a progressive increase in BSW. A third well Well 3, was also considered as a candidate due to a well integrity issue in the form of tubing-casing communication, a condition that renders surface-based sand control measures insufficient and necessitates a downhole intervention to restore well integrity. Sieve analysis was carried out on sand samples from both the TAGI reservoir (studied reservoir) and the Cambrian reservoir, the results can be directly utilized for any well in the Cambrian reservoir facing the same sand production problem. The investigation therefore moved directly to mechanical sand control methods as the most suitable remedial solution.

Chemical consolidation was not considered a viable option for these wells, as applying it to already-producing wells carries a high risk of failure besides the associated costs of workover, well kill, pre-flush, and resin job make it an expensive intervention with no guarantee of success.

This choice was further supported by PROSPER modelling, which confirmed that gravel pack completion yields a higher IPR curve compared to the current completion without sand control meaning that at the same flowing bottomhole pressure, the well delivers a significantly higher flow rate. This demonstrates that the gravel pack not only controls sand

General conclusion

production but also enhances well deliverability, making it both a technically and economically justified solution.

In conclusion, this work confirms that sand production is a critical operational problem that cannot always be managed from the surface alone. And that in many cases, the solution must be addressed from the very first moment of production. Furthermore, the analysis carried out throughout this study leads to the conclusion that gravel pack stands out as the most effective and versatile sand control method, applicable at any stage of the well's life, from initial completion through to late production.



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Annex

Table A : Different forces affecting particles transportation in porous medium:

Force	Principe	Equation
Forces Related to Transport Mechanisms		
Inertia force	The inertia of a particle causes it to maintain motion along a straight path.	$N_i = \frac{\rho_s D_p^2 v_a}{18 \mu D_g}$
Gravity force	Due to the density difference between the particle and the carrier liquid, particles tend to move in the direction of gravity according to Stokes' law.	$v_s = \frac{(\rho_s - \rho) g D_p^2}{18 \mu}$
Centrifugal forces	Centrifugal forces are generated by external acceleration created by an angular velocity and a radius of curvature.	$N_c = \frac{R_w^2 (\rho_s - \rho) D_p^2}{18 \mu v_a}$
Diffusion force	Particles smaller than 1.0 mm in diameter tend to move irregularly in a liquid medium and disperse randomly, a phenomenon known as Brownian motion.	$D = \frac{K T}{3 \pi \mu D_p}$
Hydrodynamic force	Fine particles are transported with the flowing fluid as a result of fluid shear and pressure forces.	$N_{Re} = \frac{D_g v_a \rho}{\mu}$
Forces Related to Attachment Mechanisms		
London–van der Waals Force	An attractive force resulting from electromagnetic interactions associated with the electronic properties of atoms and molecules.	$F_{vw} = \frac{1}{(s-2)^2} F_n \left(\frac{s-2}{\lambda} \right)$
Forces Related to Detachment Mechanisms		
Shearing force	When the shear stress of the liquid flowing over the deposited particles creates a shearing force greater than those attaching the particles to the grain surface, the particles are detached and mobilized.	$\tau = \mu \frac{dv}{dr}$
Electrostatic double-layer force	When the particle and grain surfaces carry electrostatic charges of the same sign, they repel each other, governed by pH and ionic strength conditions.	$F_R = \frac{\exp[-k D_p (s-2)]}{1 + \exp[-k D_p (s-2)]}$
Born repulsion force	This force is generated as a result of the overlapping of the electron clouds.	$V_{BR} = \frac{H \delta^6}{7.560} \left[\frac{8 R_p + l}{(2 R_p + l)^7} + \frac{6 R_p - l}{l^7} \right]$