بسم الله الرحمن الرحيم

Sudan university of science and technology
College of Petroleum and Mining engineering
Department of petroleum engineering

Project Title:

Optimization of Drilling Fluid to Reduce Formation Damage

تحسين خواص سائل الحفر للتقليل من التضرر الطبقي

Submitted in Partial Fulfillment of the Requirements of the Degree of B.Sc. in Petroleum Engineering

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November-2020

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Date: / / 2020

الاستـهلال

بسم الله الرحمن الرحيم

الآيـة

(وقل اعملوا فسيرى الله عملكم ورسولـه والمؤمنون وستردون
الى عالم الغيب والشهادة فينبئكم بمـا كنتم تعملون)
سورة التوبـة الآيـة (105)

Dedication

To whom our Prophet, may God's prayers and peace be upon him, told us about it that Paradise is at its feet… I do not find words of praise that give it its right, it is the joy of life ... the joy of life ... the epic of love and the example of dedication and giving ... the gift of the Lord and the candle of the path ... my beloved mother.

To my father, the compassionate, my steadfast rib ... my role model and leader ... and my idol in this life ... he taught me how to live with dignity, pride and honor.

To my brothers ... and from them, my relief and arms increased ... the warmth of my heart and reassurance ... my support and comfort ... and sharing my joys and sorrows.

To those with whom I tasted the most beautiful moments, to whom God made them my brothers in God ... to my brothers and friends ... I hope when I feel despair ... and my success when I feel failure ... my country when I feel alienated.

To this mighty scientific edifice

Sudan University of Science and Technology I give my best,

ACKNOWLEDGMENTS

My God, the night does not please you except with your thanks, and the day is not good without your obedience ... and the moments are not good without your remembrance. The hereafter is not perfected except with your forgiveness ... and heaven is not perfected without your vision, the Most Majestic

We must take our last steps in university life from a pause that goes back to the years we spent in the campus with our esteemed professors who gave us a lot, making great efforts in building the future generation to broadcast the nation again.

And before we proceed, we offer our highest verses of thanks, gratitude and love to those who beautified the most sacred message in life. To those who have made the profession of the prophets, how much do nations rise, and how high are the striving for you?

To those who paved the way to knowledge and knowledge to all our distinguished teachers

(Be a scientist ... if you cannot, be educated, and if you cannot then love the scholars, and if you cannot do not hate them)

We singled out thanks and appreciation to our Supervisor **Cons. Eng. Dr. Ahmed Abdelaziz Ibrahim** and we say to him the traps of the saying of the Messenger, may God bless him and grant him peace: (The whale is in the sea, and the bird is in the sky, they pray for the good teacher of people) And to all those who helped us in our research and this project,

D/ Omer babeker

D/Hussein

ENG/Abdoalmtalab

ENG/Ahmed khogali They light and illuminate the darkness that sometimes stood in our way and planted optimism in our path and provided us with assistance, ideas and information, without tirelessness or boredom, for they have all thanks from us.

Abstract

Generally, Formation Damage can be defined as any reduction in near well bore permeability which is the result of any material from drilling, completion, production, injection, attempted stimulation or any other well inter. Which in this study is a result of any material from drilling. This research predicts the cause of the damage using Instrumental and Laboratory Techniques to determine the source and the cause of the damage using (core analysis, X-ray diffraction (XRD), Scanning electron microscope (SEM), Thin Section Petrography (TSP), X-Ray CT Scanning (XRCT), Formation damage system) and prevent this damage from occurring by modifying the properties of the drilling fluid or by modifying the drilling conditions in general.

After all the test was done the problem associated to formation damage found to be that there is a martial coating quartz grains which was found to be mainly composed of Silica and Aluminum.

The treatment is carried out by forming a process fluid containing an aqueous fluid containing a source of hydrogen fluoride and an inhibitor of amorphous silica precipitation.

Key Words:

XRD: X-ray diffraction.

SEM: Scanning electron microscope.

TSP: Thin Section Petrography.

XRCT: X-Ray CT Scanning.

التجريد

بشكل عام، يمكن تعريف ضرر التكوين على أنه أي انخفاض في نفاذية البئر القريبة والتي تنتج عن أي مادة من الحفر، أو الإكمال، أو الإنتاج، أو الحقن، أو محاولة التحفيز أو أي بئر آخر. والتي في هذه الدراسة هي نتيجة مادة من الحفر.

يتنبأ هذا البحث بأسباب الضرر باستخدام التقنيات الآلية والمخبرية لتحديد مصدر الضرر وسببه باستخدام (التحليل الأساسي، حيود الأشعة السينية (XRD)، مجهر المسح الإلكتروني (SEM)، تصوير الصخور المقطعية الرقيقة (TSP)، المسح بالأشعة المقطعية (XRCT)، نظام تلف التكوين) ومنع حدوث هذا الضرر عن طريق تعديل خصائص مائع الحفر أو عن طريق تعديل ظروف الحفر بشكل عام. بعد إجراء كل الاختبارات، تبين أن المشكلة المرتبطة بأضرار التكوين هي وجود حبيبات كوارتز ذات طلاء عسكري والتي وُجد أنها تتكون أساسًا من السيليكا والألمنيوم.

تتم المعالجة عن طريق تكوين سائل معالجة يحتوي على سائل مائي يحتوي على مصدر فلوريد الهيدروجين ومائع لترسيب السيليكا غير المتبلور.

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CHAPTER 1

INTRODUCTION

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INTRODUCTION

1.1. Formation damage

is a generic terminology referring to the impairment of the permeability of petroleum bearing formations by various adverse processes? It is an undesirable operational and economic problem that can occur during the various phases of oil and gas recovery from subsurface reservoirs including production, drilling, hydraulic fracturing, and workover operations, it occurs in petroleum-bearing formation by various mechanisms and/or processes, depending on the nature of the rock and fluids involved. The commonly occurring processes involving rock-fluid and fluid-fluid interactions and it is caused by chemical, biological, hydrodynamic, and thermal. Interactions of porous formation, particles, and fluids cause mechanical deformation of formation under stress and fluid shear. Formation damage indicators include permeability impairment, skin damage, and decrease of well performance.(Civan, 2006)

Generally, Formation Damage can be defined as any reduction in near well bore permeability which is the result of any material from drilling, completion, production, injection, attempted stimulation or any other well inter.

As expressed by Amaefule et. al. (1988), “Formation damage is an expensive headache to the oil and gas industry.

” Bennion (1999) described formation damage as, “The impairment of the invisible, by the inevitable and uncontrollable, resulting in an indeterminate reduction of the unquantifiable!” Formation damage assessment, control, and remediation are among the most important issues to be resolved for efficient exploitation of hydrocarbon reservoirs (Subramanaya, 2006)

As expressed by Porter and Munging, formation damage is not necessarily reversible. Thus, it is better to avoid formation damage than try to restore formation permeability using costly methods with uncertain successes in many cases. When a verified generalized formation damage model becomes available, it can be used to develop strategies to avoid or minimize formation damage.(Subramanaya, 2006)

1.2. Formation Damage Mechanisms

The four main categories of formation damage mechanisms—mechanical, chemical, biological and thermal—can be divided into smaller categories.

Fines migration: occurs predominantly in clastic formations because they have a high content of transportable materials within the rock. Common fines migration remedial measures include reducing production rates, increasing the flow area by adding perforations or using openhole completions. Engineers may also inject chemical stabilizers that adhere to the surface of fines and reduce their mobility to mitigate the effects of fines migration (Schlumberger, 2016).

Chemical damage mechanisms: are generally divided into adverse rock-fluid interactions, adverse fluid-fluid interactions and near-wellbore wettability alteration. A common chemical damage mechanism is clay swelling, in which hydrophilic materials in the formation, such as reactive smectite and mixed layer clays, are hydrated and expand when interacting with fresh or low-salinity water. This swelling can severely reduce permeability when clay lines the pore throats of a formation. In formations where this potential exists, engineers use high-salinity drilling fluids or add glycols and other chemical inhibitors to keep reactive clays from becoming hydrated (Schlumberger, 2016).

Mecchanical damage mechanism: mechanical damage results from physical compaction of rock, the collapse of a weak formation is considered mechanical damage but the damage associated with perforation represents the most significant cause (Schlumberger, 2016).

Biological damage mechanism: can occur when bacteria and nutrients are introduced into the formation. Bacterial contamination is most associated with water injection operations, such as fracture stimulations, but may also occur when drilling with water-base fluids. Biological damage mechanisms can be divided into three main categories: plugging, corrosion and toxicity. Polymers secreted by bacteria may adsorb to the surface of pores in the formation and eventually plug them. Some bacteria induce hydrogen-reduction reactions that can cause corrosion, pitting and stress cracking of downhole and surface equipment. Sulfate-reducing bacteria reduce sulfates in formation or injection water and create hydrogen sulfide [H2S] gas. Biocides or oxygen scavengers may be added to drilling and hydraulic fracture fluids to prevent bacterial damage. (Schlumberger, 2016)

1.3. Problem statements

The Sudanese oil field are facing a big problem of formation damage due to the use of drilling fluids. However, this study tries to understand the causes and the processes of rock deformation in X-Field.

1.4. Objectives

The main objective of the study is trying to find a solution to reduce the damage caused by the drilling fluids.

To achieve the required purposes of the study, it will follow the Combination:

1. Laboratory core analysis test
2. X-ray diffraction (XRD), X-Ray CT Scanning (XRCT),
3. Thin Section Petrography (TSP)),
4. Scanning electron microscope (SEM),
5. Formation Damage Test.

1.5. Methodology

1. The data required to operate has been prepared.
2. Samples were also prepared from the area under study.
3. In addition to making various laboratory tests
   from X-ray diffraction (XRD), Scanning electron microscope (SEM), Thin Section Petrography (TSP) X-Ray CT Scanning (XRCT).
4. After that, formation damage test was performed.
5. Results were collected for evaluation and analysis.

CHAPTER 2

Theoretical Background and Literature Review

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Theoretical Background and Literature Review

2.1. Literature Review

In the past, numerous experimental and theoretical studies have been carried out for the purpose of understanding the factors and mechanisms that govern the phenomena involving formation damage. Although various results were obtained from these studies, a unified theory and approach still does not
exist. In spite of extensive research efforts, development of technologies and optimal strategies for cost-effective mitigation of formation damage is still as much art as science.(Civan, 2006)

Amaefule et al. (1988) classified the various factors affecting formation
damage as following:

(1) Invasion of foreign fluids, such as water and
chemicals used for improved recovery, drilling mud invasion, and workover
fluids.

(2) Invasion of foreign particles and mobilization of indigenous particles, such as sand, mud fines, bacteria, and debris.

(3) Operation conditions
such as well flow rates and wellbore pressures and temperatures.

(4) Properties of the formation fluids and porous matrix

The low permeability reservoirs in Shengli oilfield is featured by large buried depth, poor physical properties, strong diagenesis, and heterogeneity, and there exist serious water sensitivity and water lock damage during the drilling process, which significantly restricts the exploration efficiency of low permeability reservoirs. In order to solve the reservoir protection problems, novel polymer plugging agent (SLRP) and water lock prevention agent (SLWB) were optimized and characterized in detail, and the polymer plugging agent (SLRP) could work synergistically with water lock prevention agent (SLWB) to impart reservoir protection performance due to film-forming shielding effect and low surface tension. The low damage water-based drilling fluids were also established, and the results indicated that low damage water-based drilling fluids exhibited excellent reservoir protection performance with permeability recovery of above 90%, and filtrate surface tension is 18.5 mN/m. The low damage water-based drilling fluids have applied in the Bin 425 block and Da 43 block for more than 40 wells. It is concluded that acid fracturing would not be necessary to low permeability reservoirs before well production due to excellent reservoir protection performance of the low damage water-based drilling fluids, and average daily production per well could be increased to 7.63 t/d. (Liu, 2020)

Formation Damage is any reduction in near well bore permeability, which in this study is a result of any material from drilling and completion operations. This paper is applying the Wojtanowicz et. al. model in Bamboo-Sudan oilfield to study the drilling fluid effects on the Bentiu reservoir formation and the amount of formation damage. Experiments show that foreign particles invasion damage to formation could be controlled by reducing of Barite solids from (4.76%) to (2.2%). The Pore Blockage by External Particles Diagnostic Charts were obtained assuring that the damage could be control and reduced by using the optimum concentration of barite. In this study the reduction was 9.6% barite quantity in cubic meter (overall operation cost).(Abdelaziz, Elrayah and Musa, 2019)

Keeping the cost and environmental effects in mind, an alternate locally available and suitable drilling mud additive was searched for. This study focuses on the effectiveness of banana starch and corn flour starch as rheology modifier and fluid loss control agent in no damaging drilling fluids (NDDFs). Comparative study of properties obtained from the different types of starch added mud and the base mud were carried out. Starch is an environment friendly drilling mud additive used in water based drilling fluids to control filtration loss. They are also said to have thermal stability up to 250 0F. In this study, the authors have experimented to find out environment friendly alternatives for drilling fluid additives which are cheap, organic, bio-degradable, non- toxic and easily available. (Talukdar *et al.*, 2018)

A low damage drilling fluid has been developed to protect the low permeability reservoir in the Block 43, Yibei, Shengli oilfield. The development of the new drilling fluid is based on a "synergistic effect" of a drilling fluid for use in drilling low permeability reservoirs. AMP-2, a reservoir protection agent for the new drilling fluid, has strong plugging capacity and good stability; no settling has ever been found after standing for 30 days. FCS, a water blocking agent, does not settle at low temperature to -20 ℃. Invasion depth of the new drilling fluid on FA sand bed is only 4.0 cm, and on HTHP sand bed this invasion depth is 5.2 cm. The low surface tension of the mud filtrates is 22.1 mN/m, which is efficient in minimizing the damage caused by water block. Recovery of permeability is greater than 90%, an indication of good reservoir protection. Application of this drilling fluid technology on 4 wells reveals that the drilling fluid has stable performance, its properties easy to maintain, and average drilling time reduced by 11.73 days. Wells drilled with this drilling fluid do not necessitate acidization and fracturing, and flow at first production. The average flowing production rate has been

7.88 t/d. This drilling fluid has been successfully used in the Block 43, and the practices are of importance for the development of old oilfields in Shengli area. (Li, 2016)

In 2005, the scientist Sun, Y.-X & Guo, G.-H & Zhou, B.-Z. did something Following standard experimental program, Daqingzi well block in Jilin oilfield was studied systematically in aspects of mechanism of formation damage caused by drilling fluid and the influencing factors. Results indicated that:

For the core sample of about 1×10 -3 μm 2 in permeability, the damage caused by water-shut was 14.05%~23.01%,the damage caused by water sensitivity, incompatibility between drilling fluid filtrate and formation rock and adsorption of high molecule polymer was 13.73%~18.84%, and the damage caused by solid invasion was 2.30%~4.80%; 2) for the core sample of 20×10 -3~30×10 -3 μm 2 in permeability, the three values were 7.48%~12.20%, 6.47%~9.17%, and 0.57%~4.55% respectively. From above evaluation results, we can conclude that the dominant damage to Daqingzi well bock is liquid damage. Drilling fluid filtrate, especially filtrate produced in HTHP condition, affects permeability of oil reservoir greatly. That is, with the increasing of drilling fluid pressure difference, the permeability recovery of core rock reduces by 4%~7%. So, when drilling in productive formation, volume and performance of drilling fluid filtrate invaded in oil/gas formation should be controlled, and the drilling fluid density should be lowered as low as we can. (Sun, 2005)

Peng and Peden (1992) developed a simplified filtration model considering the mud cake build-up and erosion at the formation face.

Corapcioglu and Abboud (1990) developed an elaborated cake filtration model considering the particle penetration at the cake surface.

(Wojtanowicz et al. 1987and 1988) analyzed various damage processes considering porous thin slice of material and assuming genteel mechanism dominates at a particular condition. Porous medium conceived as having circuitous pathways Nh tubes with the same equivalent mean of hydraulic diameter Dh

Keelan and Koepf (1977) explain that drilling mud ’s contains solid particles that form a filter cake over the wellbore wall, the filter cake restricts the mud flow into the near well bore formation, but some filtrate and fine particle invasion are unavoidable and usually occurs. The released particles and the fine particles carried into the formation by the filtrate can plug the pores and reduce permeability of the formation. The water-based filtrates increase the irreducible water saturation and create water block and hydrocarbon permeability reduction.

2.2. Theoretical Background

2.2.1. Drilling Fluid

Drilling fluids are fluids that are used during the drilling of subterranean wells. They provide primary well control of Subsurface pressures by a combination of density and any Additional pressure acting on the fluid column (annular or Surface imposed). They are most often circulated down the Drill string, out the bit and back up the annulus to the surface So that drill cuttings are removed from the wellbore.

- **Water-based drilling:**

Water-based drilling fluids consist of a mixture of solids, liquids, and chemicals, with water being the continuous phase. Solids may be active or inactive. The active (hydrophilic) solids such as hydra table clays react with the water phase, dissolving chemicals and making the mud viscous. The inert (hydrophobic) solids such as sand and shale do not react with the water and chemicals to any significant degree.

Basically, the inert solids, which vary in specific gravity, make it difficult to analyze and control the solids in the drilling fluid (i.e., inert solids produce undesirable effects). The most common types of additives used in water-based mud:

- **Weighting Agents:**

The most important weighting additive in drilling fluids is barium sulfate ($BaSO_4$). Barite is a dense mineral comprising barium sulfate. The specific gravity of barite is at least 4.20 g/cm3 to meet API specifications for producing mud densities from 9 to 19 lb./gal. However, a variety of materials have been used as weighting agents for drilling fluids including siderite (3.08 g/cm3), calcium carbonate (2.7–2.8 g/cm3), hematite (5.05 g/cm3), ilmenite (4.6 g/cm3), and galena (7.5 g/cm3).

- **Fluid-Loss-Control Additives:**

Clays, dispersants, and polymers such as starch are widely used as fluid-loss control additives. Sodium montmorillonite (bentonite) is the primary fluid-loss-control additive in most water based drilling fluids

- **Thinners or Dispersants:**

Although the original purpose in applying certain substances called thinners was to reduce flow resistance and gel development (related to viscosity reduction), the modern use of dispersants or thinners is to improve fluid-loss control and reduce filter cake thickness

- **Lost-Circulation Materials:**

An immense diversity of lost-circulation materials has been used. Commonly used materials include:

- Fibrous materials such as wood fiber, cotton fiber, mineral fi beer, shredded automobile tires, ground-up currency, and paper pulp

- Granular material such as nutshell (fi ne, medium, and coarse), calcium carbonate (fi ne, medium, and coarse), expanded perlite, marble, Formica, and cottonseed hulls
- Flake like materials such as mica fl aces, shredded cellophane, and pieces of plastic laminate.(Hyne, 2012)

2.2.2. Testing drilling fluid properties

Routine testing is carried out on drilling fluids to determine the following: the density or mud Weight; viscosity; gel strengths, filtration rate
(Also called fluid loss); sand content; solids, oil and water content; and chemical properties.(Fluids, 2014)

(1) Density or mud weight:

Density or mud weight is the mass per unit Volume. In the field, it is measured with a mud Balance and is most often reported in pounds Per gallon (lb./gal or ppg); specific gravity or SG (g/ml); kilograms per cubic meter (kg/cum); or pounds per cubic foot (lb./cu ft.). Density Is used to determine the hydrostatic pressure of the mud column and can also be measured and expressed as a gradient such as pounds per square inch per thousand feet (psi/1,000 ft.). This allows for easy calculation of the hydrostatic pressure at any depth. The mud scale is calibrated with water (freshwater weighs8.34 lb./gal and seawater weighs 8.55 lb./gal). The midscale has four unit's scales graduated on the beam: lb./galore pgg, g/cc, lb/cu ft. and psi/1,000 ft.(Fluids, 2014)

(2) Viscosity:

Viscosity is a measure of the drilling fluids internal resistance to flow, or how thick or thin it is. Drilling fluids are non-Newtonian, meaning that their viscosity is not constant for all shear rates. These non-Newtonian fluids behave very differently than liquids like water or oil which are Newtonian with a constant viscosity *regardless of shear rate. Non-Newtonian drilling fluids are shear thinning such that they have lower viscosity at high-shear rates and higher viscosity at low-shear rates. This is desirable for drilling where minimum pressure losses are wanted for the high-shear conditions inside the narrow bore of the drill string. Higher viscosity is wanted in the low-shear conditions of the larger annulus.

Direct indicating rotational viscometer is used to measure the viscosity at different shear rates to determine the rheology model coefficients. For field operations, the Bingham plastic rheology model coefficients of plastic viscosity (PV) and yield point (YP) are monitored. These two coefficients are used to monitor the non-Newtonian properties of the drilling fluid. These viscometers indicate the shear stress as a "dial unit" or "degree" (ϴ) at a given shear rate (one dial unit equals about 1 lb./100 sq. ft.). The dimensions of the direct
indicating viscometer are selected so that the PV and YP can be quickly calculated from the shear stress values measured at shear rates of 600 and 300 rpm. The PV in centipoise (cps) is calculated from the 600-rpm dial reading
(ϴ600) minus the 300-rpm dial reading (ϴ300). The YP in lb./100 sq. ft. is then calculated from the 300-rpm dial reading minus the PV.
(Fluids, 2014)

(3) Filtration or fluid loss:

Filtration or fluid loss is a relative measure of the liquid that could invade a permeable formation through deposited mud solids. This liquid is called filtrate and the deposited solids are called filter cake or mud cake. There are two standard filtration tests that measure the volume of filtrate collected after a 30-min period of time using filter paper. These tests are the low-temperature/low-pressure fluid loss test, often called the

American Petroleum Institute (API) test, and the high-temperature high-pressure (HTHP) test. Results are reported as the milliliters (ml) which flow through a 7.1-sq in. area. The HTHP filtration test unit is a half-area (3.5-sq in.) press; therefore, the measured filtrate value is doubled
for reporting. Filter cake thickness is measured and reported in units of 1/32 in. (or millimeters where SI units are used).

A filter cake thickness of 3 means 3/32 in. The basic filtration test is called the low-temperature/ low-pressure or API fluid loss test and is performed at ambient temperatures and 100 psi. The more advanced test is the HTHP filtration test that is performed at a temperature closer to the bottom hole temperature and at a 500-psi differential pressure. While there is no standard temperature for the HTHP test, temperatures between 275°F and 325°F are often set as the standard. This, of course, is dependent on the area and operator. The HTHP test should preferably be run at the actual bottom hole temperatures and differential pressures existing in the wellbore, if possible. Filtration rate and filter cake thickness are both monitored and reported properties. High fluid loss and thick filter cakes significantly increase the possibility of having differentially
stuck pipe. A desirable filter cake is one that has ultralow permeability and is thin, tough, compressible and slick (lubricious).

These desirable properties cannot be determined from the fluid loss values alone and many low fluid loss drilling fluids do not have a good quality filter cake. A desirable filter cake is achieved by minimizing the drill solids content (colloidal-sized solids) of the drilling fluid and maintaining the proper concentration of filtration control additives. For most WBMs, the best quality filter cake is achieved by using an adequate quantity of high-quality bentonite.(Fluids, 2014).

(4) Gel strengths:

Gel strengths refer to the shear stress required to initiate flow after static periods of time. They are a measure of the degree of gelatin that occurs due to the attractive forces between particles over time. Higher gel strengths are reported in the same units as YP (lb/100 sq ft). Sufficient gel strength will suspend drill cuttings and weighting materials during connections and other static conditions. Gel strengths directly affect surge and swabbing pressures when making connections, tripping pipe or running casing. They also affect the pressure required to "break circulation" and the ease of releasing entrained gas or air. Gels are determined using the same direct indicating rotational viscometer as is used for viscosity. They are measured by observing the maximum shear stress value while slowly turning the rotor or by using the 3-rpm setting after being static for some period of time. Standard values for gel strength are taken after 10 sec, 10 min and sometimes after 30 min. The change in gel strength values between these time periods also give an indication if the fluid is continuing to gel with longer periods of time (called progressive gels) or if it has reached a relatively constant value (called flat gels). (Fluids, 2014)

(5) Sand content:

Sand content refers to the volume percent of whole mud that are "sand sized" particles, meaning they are larger than 74 microns and do not pass through a 200 mesh screen. These may be actual quartz sand or may be the coarse-sized barite particles, sized bridging solids, LCM, drilled solids or any other particles larger than 74 microns. Sand content is measured using a sand content graduated glass tube, funnel and 200 mesh sieve. It is monitored to gauge the effectiveness of solids control equipment, the shale shaker screen condition and the potential for increased abrasion to mud pumps and other equipment in the circulating system including drill string and down hole equipment.(Hyne, 2012)

(6) Solids, oil and water content:

Solids, oil and water content are measured using a distillation report. With this information and other data from the chemical analysis, a complete breakdown of the composition of the drilling fluid can be made, often called a solids analysis. This will include oil content, water or brine content, low-gravity solids (mainly drill solids) and high-gravity solids (normally barite). Solids content affects drilling rate, flow properties, gel strengths and the overall stability of the mud. Often, the frequency of dilution and chemical treatments are based on the results from this analysis. Optimum solids content and good solids control is essential for overall superior mud performance**.**(Alhetari, 2017)

(7) Chemical content:

Chemical tests are carried out on the whole mud and filtrate to monitor specifications and to identify contamination. Depending on the type of drilling fluid being used, these tests may include: pH, various measures of alkalinity (PM, PF, and MF for WBM and P OM for NAF), lime content, chloride (or salt), calcium (or total hardness), carbonate/bicarbonate, sulfate, methylene blue test (MBT), H2S, electrical stability, water activity and others.(Hyne, 2012)

2.2.3. Formation Damage Causes by Drilling Fluid

Formation damage is a serious problem which starts from the very early life of the well. Drilling operation itself is potential source of formation damage.

There are two causes of formation damage by drilling fluids: solids invasion and filtrate invasion.

Invasion of mud solids into the reservoir rocks and the drilling fluid rock interactions result in formation damage. To understand the effect of fines on the formation, an accurate definition of fines is required. As stated by Byrne, fines are any part of the rock that can move through or within the pores of the rock.(Civan and Chair Professor, 2006)

Solids and fines mixed with drilling mud are trapped inside the reservoir tortious paths inside the rock matrix. As a result, drilling fluid invasion into the reservoir damages the formation by blocking the pores or by contamination near the wellbore.

Filtrate invasion can cause different types of formation damage: scale precipitation by incompatible formation brines and filtrate, swelling and dispersion of clays in sandstone reservoirs, emulsion with reservoir hydrocarbons, wettability alteration, and water blockage in tight gas reservoirs **(Hamoud A. Al-Anazi, et al, 2009)**

For the efficient hydrocarbon exploitation, the most important issues are the damage grading (assessment, control, and remediation). The damage could be irreversible; thus, it is better to degrade damage towards its minimum than trying to restore permeability using uncertain successes precious methods.(Alhetari, 2017)

Fine particles are trapped inside the pores during filtration process. Such accumulation results in porosity decrease as well as permeability. As shown **Figure (2.1)** the particle/pore size ratio is very important parameter in filtration operations because the larger the ratio is the higher tendency for damage to happen for the formation near the wellbore.

Solid and liquid particles dispersed in the drilling fluid (mud) are trapped by the rock (porous medium) and permeability decline takes place during drilling fluid invasion into reservoir resulting in formation damage. The formation damage due to mud filtration is explained by erosion of external filter cake. (Alhetari, 201

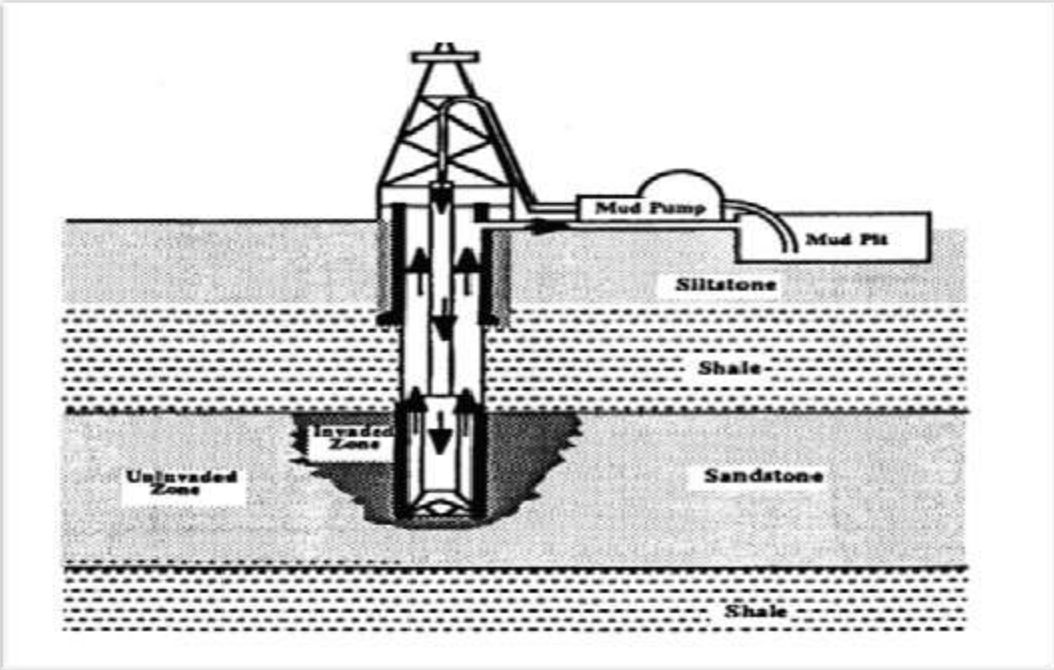


Figure (2.1): Filtrate invasion (Alhetari, 2017)

2.2.4. Instrumental and Laboratory Techniques for Characterization of Reservoir Rock

Reservoir rock evaluation is a very extensive task requiring a multidisciplinary effort and knowledge of instrumentation, testing and interpretation, and cross-correlation of various types of data. It is a continuously evolving area of science and engineering.

In this section the frequently used techniques for determination of the characteristics of petroleum-bearing rocks and their operating principles are briefly reviewed.

Evaluation of reservoir formation sensitivity to changing conditions during petroleum reservoir exploitation requires a multi-disciplinary team effort and the integration of various instrumental and analytical approaches (Kersey, 1986; Amaefule et al., 1988; Unalmiser and Funk, 1998).

Some methods, such as well test interpretation, may be used to infer for limited information on a few critical parameters of reservoir formation. However, direct measurements of core properties at reservoir conditions are preferred, because they provide the most realistic information about the petroleum-bearing formations.

The fundamental analytical techniques available for laboratory evaluation of core samples for sensitivity and damage potential are briefly described in this chapter. For operational principles and detailed descriptions, the readers are referred to manufacturers' manuals and other pertinent sources.(Civan and Chair Professor, 2006).

2.2.4.1. core analysis:

Core data developed on rock samples recovered from a formation of interest play a vital role in exploration programs, well completion and workover operations, and in well and reservoir evaluations. Core data are provided by core analysis, and yield positive evidence of oil presence, storage capacity for reservoir fluids (porosity), and flow capacity and distribution (permeability) expected. Residual fluid contents allow interpretation of probable production of oil, gas, or water.

Study of core analysis data, coupled with supplementary test information developed on core samples, yields insight into reservoir performance and unusual response to well treatment, provides a sound basis for reserve estimates and reservoir modeling, enhances log interpretation, and supplies guidance in secondary and tertiary recovery programs. Basic rock property data developed in field laboratories located near hydrocarbon productive areas have been extended through tests referred to as Especial Core Analysis. The latter are completed in a central laboratory, and utilize specialized equipment. Basic core analysis data are normally available within hours, whereas the special tests often require six to eight weeks or longer to complete. The disadvantage of this time factor can be overcome in most cases by first recognizing that it exists, and then planning to secure needed data early in the coring program. (Faruk Civan, 2000)

2.2.4.2. X-ray diffraction(XRD):

The X-ray powder diffraction analysis (XRD) is a nondestructive technique that can provide a rapid and accurate mineralogical analysis of less than 4-micron size, bulk and clay contents of sedimentary rock samples (Amaefule et al., 1988). This is accomplished by separately analyzing the clays and the sand/silt constituents of the rock samples (Kersey, 1986).

The X-ray diffraction technique is not particularly sensitive for nanocrystal line materials, such as amorphous silicates and, therefore, an integrated application of various techniques, such as polarized light microscopy, X-ray diffraction, and SEM-EDS analyses, are required (Braun and Boles, 1992). Hayatdavoudi (1999) shows the typical X-ray diffraction patterns of the bulk and the smaller than 4micron size clay fractions present in a core sample.(Civan, 2006)

2.2.4.3. Scanning electron microscope (SEM):

The rock and fluid interactions causing formation damage is a result of direct contact of the pore filling and pore lining minerals present in the pore space of petroleum-bearing formations. The mineralogical analysis, abundance, size, and topology and morphology of these minerals can be observed by means of the scanning electron microscopy (SEM) (Kersey, 1986; Amaefule et al., 1988). Braun and Boles (1992) caution that, although the SEM can provide qualitative and quantitative chemical analyses, it should be combined with other techniques, such as the polarized light microscopy (PLM) and the X-ray diffraction (XRD) to characterize the crystalline and monocrystalline phases, because amorphous materials do not have distinct morphological properties. An energy dispersive spectroscopy (EDS) attachment can be used during SEM analysis to determine the iron-bearing minerals (Amaefule et al., 1988).

Various specific implementations of the SEM are evolving. For example, the environmental SEM has been used to visualize the modification of the pore structure by the retention of deposits in porous media (Ali and Barrufet, 1995).

Typical SEM photomicrographs are shown by Amaefule et al. (1988). The environmental SEM images shown by Ali and Barrufet (1995) illustrate the modification of the pore structure by polymer retention in porous media. As can be seen by these examples, the SEM can provide very illuminating insight into the alteration of the characteristics of the porous structure and its pore filling and pore lining substances.

The cryo-scanning electron microscopy has been used to visualize the distribution of fluids in regard to the shape and spatial distribution of the grains and clays in the pore space (Durand and Rosenberg, 1998).

The SEM has also been used for investigation of the reservoir-rock wettability and its alteration (Robin and Cuiec, 1998; Durand and Rosenberg, 1998). The SEM operates based on the detection and analysis of the radiations emitted by a sample when a beam of high energy electrons is focused on the sample (Ali and Barrufet, 1995). It allows for determination of various properties of the sample, including its composition and topography.(Ali and Barrufet, 1995)

2.2.4.4. Thin Section Petrography (TSP):

The thin section petrography technique can be used to examine the thin sections of core samples to determine the texture, sorting, fabric, and porosity of the primary, secondary, and fracture types, as well as the location and relative abundance of the detrital and antigenic clay

minerals and the disposition of matrix minerals, cementing materials, and the porous structure (Kersey, 1986; Amaefule et al., 1988).

Amaefule teal. (1988) show the examples of typical thin section photomicrographs.(Civan , 2006)

2.2.4.5. X-Ray CT Scanning (XRCT):

X-Ray CT (computer-assisted tomography) scanning is a nondestructive technique, which provides a detailed, two- and three-dimensional examination of unconsolidated and consolidated core samples during the flow of fluids, such as drilling muds, through core plugs and determines such data like the atomic number, porosity, bulk density, and fluid saturations (Amaefule et al., 1988; Unlimber and Funk, 1998). This technique has been adapted from the field of medical radiology (Wellington and Vinegar, 1987). As depicted by Hicks Jr. (1996), either an X-ray source is rotated around a stationary core sample or the core sample is rotated while the X-ray source is kept stationary. The intensity of the X-rays passing through the sample is measured at various angles across different cross sections of the core and used to reconstruct the special features of the porous material. The operating principle is Beer's law, which relates the intensity of the X-ray, through the linear attenuation coefficient, to the physical properties of materials and different fluid phases in the sample (Wellington and Vinegar, 1987; Hicks Jr., 1996).(Civan and Chair Professor, 2006)

A schematic of a typical X-ray scanning apparatus is shown by Coles et al. (1998). The image patterns can be constructed using the linear attenuation coefficient measured for sequential cross-sectional slides along the core sample as shown by Wellington and Vinegar (1987). These allow for reconstruction of vertical and horizontal, cross-sectional images, such as shown by Wellington and Vinegar (1987). Three-dimensional images can be reconstructed from the slice images as illustrated by Coles et al. (1998). Tremblay et al. (1998) show the cross-sectional and longitudinal images of a typical wormhole, perceived as a high permeability channel, growing 108 Reservoir Formation Damage in a sand-pack. Such images provide valuable insight and understanding of the alteration of porous rock by various processes.(Civan , 2006)

2.2.4.6. Formation damage system:

Frequently, the formation damage potential of petroleum bearing formations and methods of circumventing and remediation of formation damage are investigated by subjecting the reservoir core samples to flow at near-in situ conditions in the laboratory. The scenarios planned for field applications are simulated in the laboratory under controlled conditions and the response of the core samples under these conditions are measured.

The tests carried out over a range of variables yield valuable data and insight into the reaction of the core samples to fluid conditions and its effect on the alteration of the core properties. These data can be used for model assisted analysis of the processes leading to formation damage.

This exercise yields important information about the relative contributions of the various mechanisms to formation damage and help determine the values of the relevant process parameters. This information can be used to simulate the formation damage processes at the field scale. This, then, provides a valuable tool for quickly reviewing and screening the various alternative scenarios and optimizing the field applications to avoid or minimize the formation damage problems in the field.

For meaningful formation damage characterization, laboratory core flow tests should be conducted under certain conditions (Porter, 1989; Mungan, 1989):

- Samples of actual fluids and formation rocks and all potential rockfluid interactions should be considered.
- Laboratory tests should be designed in view of the conditions of all field operations, including drilling, completion, stimulation, and present and future oil and gas recovery strategies and techniques.
- The ionic compositions of the brines used in laboratory tests should be the same as the formation brines and injection brines involving the field operations.
- Cores from oil reservoir should be unextracted to preserve their native residual oil states.

This is important because Mungan (1989) says that "Crude oils, especially heavy and asphaltenic crudes, provide a built-in stabilizing effect for clays and fines in the reservoir, an effect that would be removed by extraction."

(1) Core Preparation and Characterization (Cutting and Trimming the Plugs):

Plugs should be cut to give a minimum diameter of 1 inch (2.54 cm). Larger plugs, sized to fit particular core holders are preferable.

The samples should have a minimum length of 1 inch (2.54 cm) and should be taken from the center of the core to minimize the impact of any coring fluid invasion. The plugging method and drill bit lubricant used during plugging will be determined by the state of preservation of the sample and the reservoir type. Cutting Consolidated Core. A standard core analysis rotary core plugged should be used with lubricant selected. (oilfieldwiki, 2020)

(2) Mounting and Labeling the Plugs:

At this stage the samples should be encased in inert material leaving the end faces exposed, using PTFE tape, together with heat shrink tubing. For poorly consolidated samples it may also be necessary to apply restraining grids to the plug end faces. The samples should be assigned a wellbore and a formation end face which are annotated on the side of the plug and not on the end faces. (oilfieldwiki, 2020)

(3) Cleaning and Drying:

Once a cleaning and drying method has been selected, it should be identical for all samples in a particular study. (oilfieldwiki, 2020)

(4) Plug Selection:

Selection of Duplicates. Prior to the flood tests, a sufficient number of duplicate plugs should be selected so that the entire test program can be conducted using essentially the same sample of rock. The following criteria are to be used during plug selection:

a. Similar permeability (preferably within 20% as determined by Ki (or K0 for native state samples) measurement

b. Similar grain size/pore throat size distribution (determined by SEM, thin section and possibly mercury injection of plug trims or carcass material)

c. Similar composition/lithology (determined by XRD, SEM, thin sections of trims/carcass or CT scans of plugs)

It is difficult to quantity the parameters in b) and c) and the comparative suitability of duplicates must be made using expert judgement. (oilfieldwiki, 2020)

(5) Plug Saturation:

100% saturation is defined as being within 2% of base saturation. Saturation with Formation Brine. Cleaned samples should initially be saturated with formation brine (oilfieldwiki, 2020)

(6) Fluid Preparation:

- **Simulated Formation Water:**

Simulated formation water (SFW) should be prepared using analytical grade inorganic salts to obtain the appropriate levels of the ions, as determined by elemental analysis, and then degassed. The SFW should be filtered to 0.45 micron. (oilfieldwiki, 2020)

- **Fluids Used for Initial and Final Permeability's:**

Kerosene or Inert Mineral Oil. Kerosene or inert mineral oil should be filtered to 0.45 micron. Formation Brine. Formation brine, if available, should be filtered to 0.45 micron at reservoir temperature.

- **Wellbore Fluids:**

Drilling Fluid (Whole Mud). Drilling fluids to be used in return permeability testing should be as representative as possible. In the case of laboratory prepared muds, they should contain all the components of the proposed formulation including weighting agents and contaminants and should be mixed according to standard API procedures where available.

- **Wellbore Fluid Placement.**

The prepared sample for evaluation should be loaded into a core holder capable of attaining reservoir net confining pressure and temperature ratings for the matching of reservoir in situ conditions. Pressures and flow rates should be continuously logged as functions of time. The core sample should be mounted in the horizontal position for analysis. The confining stress on the sample should be gradually increased while at the same time the pore pressure of the fluid in place is also increased to maintain a net confining stress ratio equivalent to the in situ reservoir stress conditions. The rate of increase of net stress on the sample should not exceed 1000 psi (68 bar) per hour.

- **Initial Permeability:**

Formation fluid should be flowed in the production direction (from "formation to wellbore") by injection at constant rate. Where the critical velocity is not known, the flow rate should be as low as possible yet sufficient to generate a measurable pressure drop. Where the critical velocity is known for the test material, then the flow rate should be <50% of the critical rate. The differential pressure across the sample should be recorded. Particular regard should be paid to anomalies caused by mobilization of fine material within the test sample. The flow should be maintained until the pressure drop has stabilized and does not vary by more than 5% for a minimum of 10 pore volumes. Fluid flow is ceased once initial permeability is established.

- **Drilling Fluid Placement:**

Whole Mud. To simulate well conditions, drilling fluid should be flowed over the 'wellbore' face of the sample. The drilling fluid should be pre-heated prior to placement to match the bottom hole temperature. The drilling fluid should be applied to the sample face at the same overbalance pressure as in the reservoir and should be dynamically circulated over the face of the test sample for a minimum of 4 hours. Where comparative testing of mud on the formation is required the mud flow rate will be a constant for each mud type. During circulation the drilling fluid pressure and pore pressure should be recorded to ensure the values remain stable (less than 5% variation). During dynamic drilling fluid circulation, the amount of fluid invasion into the test sample should be monitored at the "formation" end of the sample.

The method of monitoring should be recorded. Invasion volume as a function of time should be recorded to allow the evaluation of spurt loss as the mud cake builds up and the effectiveness of the cake to prevent filtrate invasion into the test sample (leak off). Static drilling fluid placement should follow the dynamic placement. During the static placement the mud pressure should be maintained without flowing fluid over the "wellbore" face of the sample. The static placement should be for a minimum of 16 hours. As in the dynamic placement, recording of invasion volume as function of time measured at the "formation" face of the sample during the static placement is required to monitor mud cake performance. Following the static placement, the mud should be dynamically circulated for a minimum of 1 hour. A fluid system that requires a wash or breaker fluid, will need to have a step included into the test sequence in which placement and contact with this fluid are simulated. (oilfieldwiki, 2020)

The follow work discusses the practical steps for determination of the causes of formation damage and reducing this effect by alterating the composition of drilling fluid.

CHAPTER 3

METHODOLOGY

CHAPTER 3

METHODOLOGY

This chapter discusses the practical steps for determination of the causes of formation damage and reducing this effect by alternating the composition of drilling fluid.

3.1. Drilling Fluid Calculation

- The drilling fluid was prepared and a routine test was made to determine the following: the density or mud Weight; viscosity; gel strengths, filtration rate (Also called fluid loss); sand content; solids, oil and water content; and chemical properties.
- The rheological properties were calculated from the following equations:

$$\textbf{PV (cps)} = \varphi\, 600 - \varphi\, 300$$

$$\textbf{YP (lb./100 sq. ft.)} = \varphi\, 300 - \textbf{PV}$$

3.2. Experimental Program and Procedures

The experimental program and procedures are following the below diagram, figure (3.1)

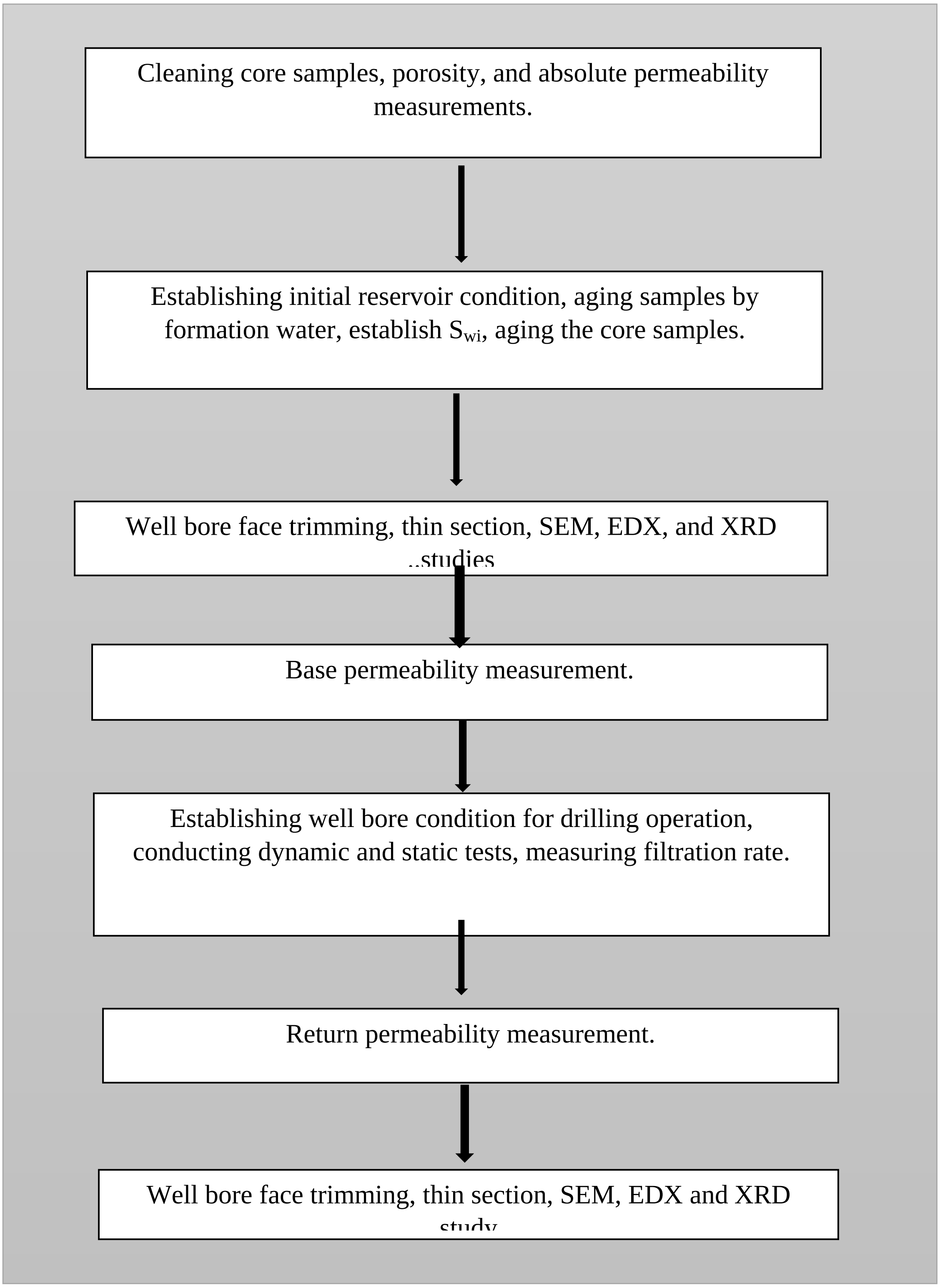


Figure (3.1): Experimental Program and Procedures Diagram

3.2.1. Core Lab Procedures:

A composite core model prepared from core samples 8 and 7, to simulate near well bore and deep reservoir samples in X-1 respectively. A filter paper has been placed between the samples in order to ensure the continuity of the fluid movement between them. Similar procedures have been used for X-2 where the second composite core model made from core plug samples 10 and 47 to simulate near well bore and deep reservoir samples respectively. See the figure (3.2) and (3.3).

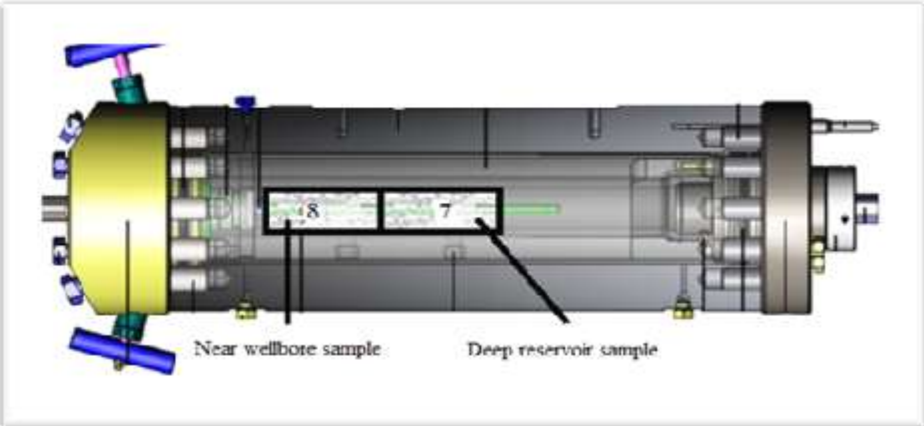
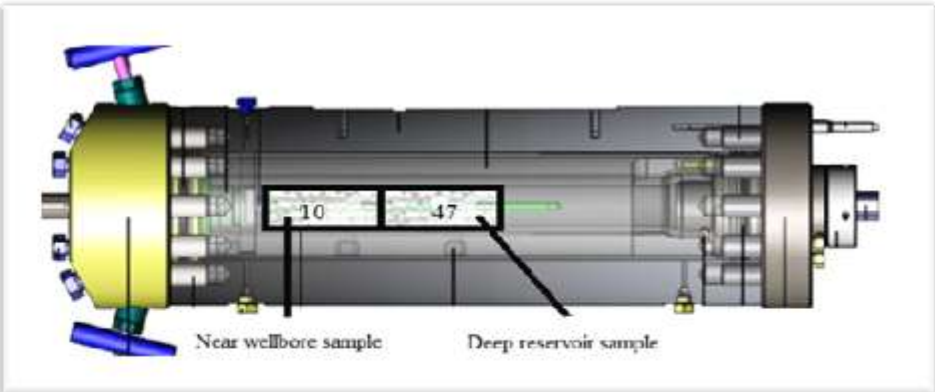


Figure (3.2): Configuration of the core samples in experiment for x-1



well

Figure (3.3): Configuration of the core samples in experiment for x-2 (Formation damage lab report)

All experiments have been performed in reservoir condition at high pressure and temperature while applying overburden pressure. In order to simulate the overbalance drilling operation at reservoir temperature, the initial overburden and pore pressure were considered close to the reservoir condition.

3.2.2. X-ray diffraction(XRD):

- The sample to be studied was prepared and inserted into the XRD device to find out the constituent minerals before testing the slurry.
- After identifying the minerals, the percentage of each mineral in the sample was calculated by means of the soft were present in the device.
- The same previous steps were taken after testing the clay

. **Figure (3.4): Show XRD device (From Ministry of Energy and Mining)**

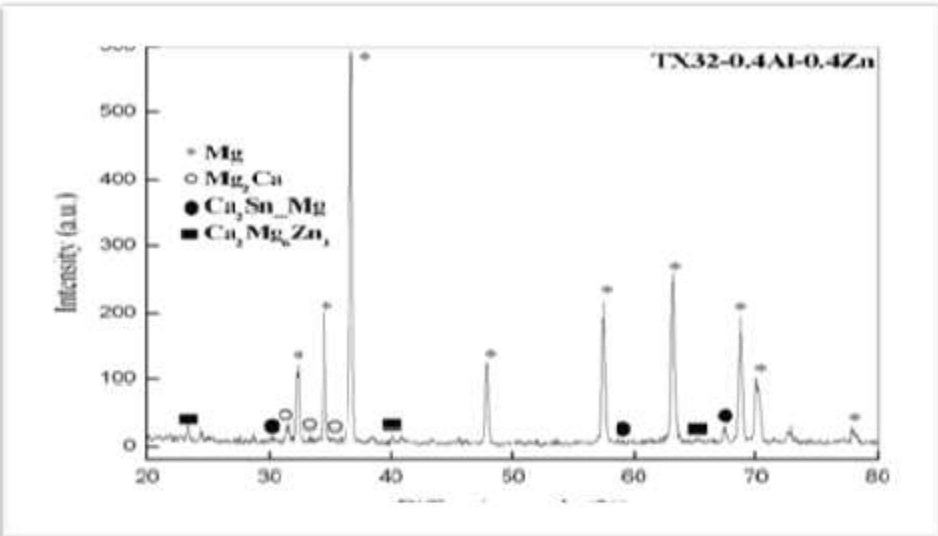


Figure (3.5): show example of XRD scanning (XRD lab report)

3.2.3. Scanning electron microscope(SEM):

Scan-electron microscopy has been applied to the study before and after the mud injection:

- Based on the XRD results, the sample is prepared to work with (SEM) a specific area (especially in the sample pores).
- The sample was inserted into a SEM that uses electrons to create a three-dimensional image of the sample.
- The minerals in the sample were identified before mud test.
- The same previous steps were done for the sample after mud test(https://www.jove.com/v/5656/scanning-electron-microscopy-sem)

Figure (3.6): SEM device (From Ministry of Energy and Mining)

3.2.4. Thin Section Petrography (TSP):

- A thin piece of the sample was cut visually flat.

- The thin piece was mounted on a glass slide, and milled smoothly until the sample thickness was 30 µm.
- They are placed between two polarizers and set at right angles to each other.
- The minerals that make up the sample have been identified (because different minerals have different optical properties).

Figure (3.7): Thin Section Petrography (TSP)

3.2.5. X-Ray CT Scanning (XRCT):

CT scan study is performed in order to choose the best rock samples, which h**as not crack and fracture.**

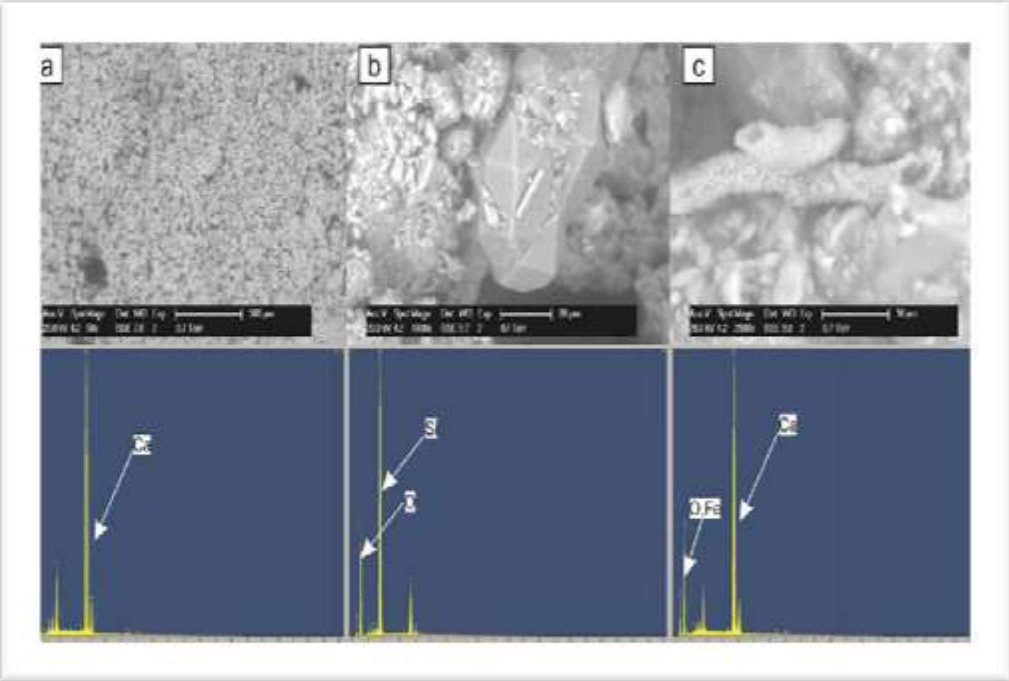


Figure (3.8): Environmental scanning electron micrographs of initial soil sample pre-irrigation and detail of a silica particle and menisci (Ali and Barrufet, 1995)

3.2.6. Laboratory Formation Damage Tests:

- The sample was prepared by cleaning it from oil, water, and solids that were in it.
- The permeability and porosity of the sample were also read by Darcy's law of permeability and Boyle's law for porosity:

Darcy's law:

$$Q = \frac{-\kappa A(p_b - p_a)}{\mu L}$$

(Shekhar, 2017)

Boyle's law:

φ = Pore volume / Bulk volume(Boyle, 2011)

- The sample was 100% saturated with laboratory prepared water and the porosity was measured.
- The water-saturated sample was placed in the station (FDS), and oil was pumped into the sample (after applying some filtering treatments to it, etc.) until all the existing water came out other than what is called "connate water saturation".
- The permeability of the sample, known as":Initial Permeability" was read. The fluid was pumped under two conditions:

    In the case of "Dynamic mud", the pressure is higher than the formation pressure.

    In the case of "Static mud" without circulation and leaving it for a period of time, the final permeability was calculated.

- Then the damage resulting from this process was evaluated by calculating the skin factor of the initial permeability and final permeability:

    Initial permeability divided final permeability…

    S = Initial permeability/ final permeability

Figure (3.8): shows the apparatus used to study the formation damage at overbalance condition. The formation damage system (FDS350) is a unique equipment for study of created damage in the formation due to invasion of the drilling fluid to the formation in static and dynamic condition.

Figure (3.9): formation damage system (FDS350) (formation damage lab report)

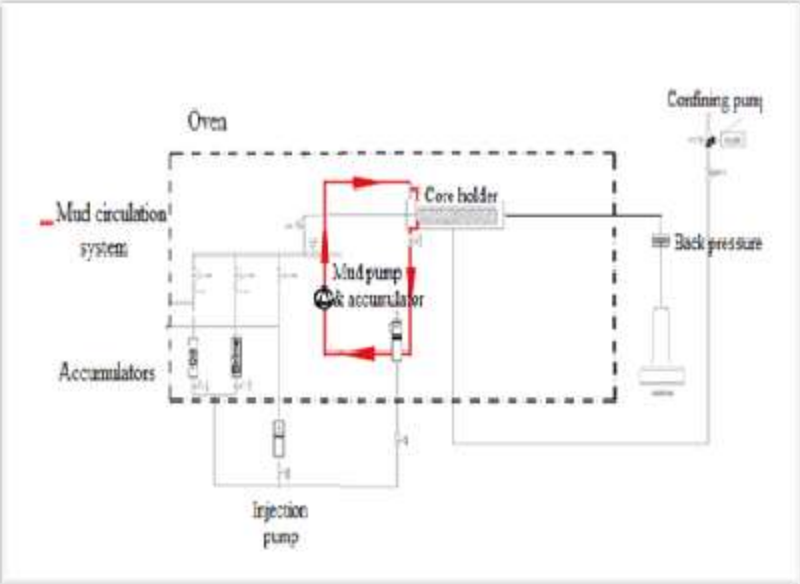


Figure (3.10): Formation Damage System (formation damage lab report)

CHAPTER 4

Results and Discussion

CHAPTER 4
Results and Discussion

The results of the laboratory test which was listed in previous work will be discussed.

data collection

Tables (4.1), (4.2) and (4.3) which show the experimental conditions, fluid and rock properties and drilling fluid composition.

Table (4.1): Experimental conditions

Model	Pore pressure Psi	Overburden pressure Psi	Reservoir temperature °C
x-1	2000	3000	70.0
x-2	3200	6400	98.5

Table (4.2): Fluid and rock properties

Salt	Well # 17	Well # 21
$CaCl_2*2H_2O$ (gr)	1,14	0,19
$MgCl_2*6H_2O$ (gr)	0,13	0,08
KCl (gr)	6,90	1,12
$NaHCO_3$ (gr)	1,29	9,98
NaCl (gr)	0,25	14,39

Table (4.3): Composition of the drilling fluid

Product	Function	Concentration (ppb)	Chemical name
KCL	Inhibitor	18-20	Potassium chloride
PAL ZAN-D	Viscosifying Agent	0.5-2.0	Clarified Xanthan Gum
PAL SIL N 2.7	Primary Inhibitor	9.5-10.5	Sodium silicate
Soda Ash	Alkalinity & hardness treatment	0.25-0.5	Sodium carbonate
PAL PAC LV-X	Fluid Loss Control Additives	2.0-6.0	Poly Anionic Cellulose

The mud rheology results are tabulated as in tables (4.4), (4.5)

Table (4.4): The rheological measurements for the mud including readings from low and standard 300 and 600 RPM.

	Mud Rheology
φ_{600}	20
φ_{300}	15
φ_{200}	11
φ_{100}	9
φ_{6}	4
φ_{3}	4

Table (4.5): Fluid test results for The apparent viscosity (AV), plastic viscosity (PV), and yield point:

	Mud Rheology
AV (cP)	10
PV (cP)	5
YP (lb/100sq ft)	10

The XRD analysis results are tabulated in table (4.6)

Table (4.6): XRD analysis (Clay) for Composite model x-1 before and after mud test

Sample No.	Kaolinite	Smectite	Illite	Chlorite	Smec/Illi
Before Test	98,42	0,2	0,88	0,3	0,2
Deep Reservoir	90,47	5,52	2,67	0,45	0,61
Near well-bore	83,7	7,35	7,83	0,67	0,45

The results of XRD showed the presence of the following minerals: Kaolinite, smectite, illite, chlorite, Plus, a mixed layer (smectite/illite). Also note that the percentage of kaolinite in the sample is very large compared to other minerals.

The SEM result shown in figure (4.1), (4.2) and (4.3).

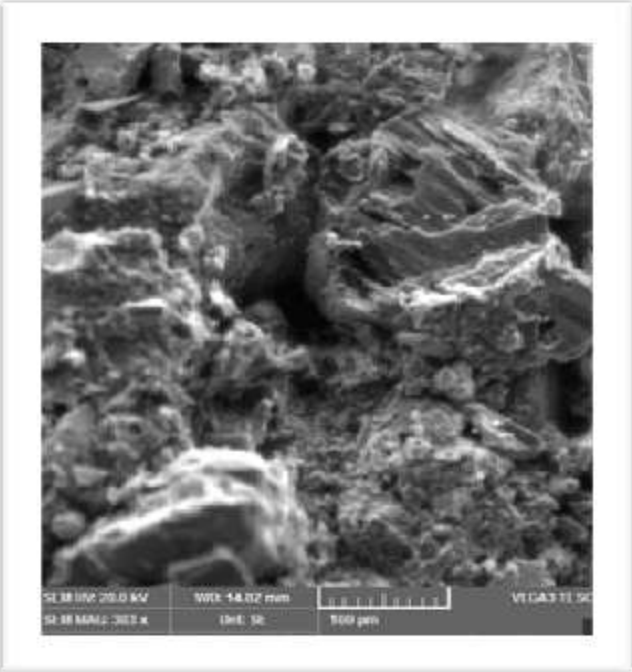


Figure (4.1): SEM picture before mud test for Sample x-1 (Near Wellbore)

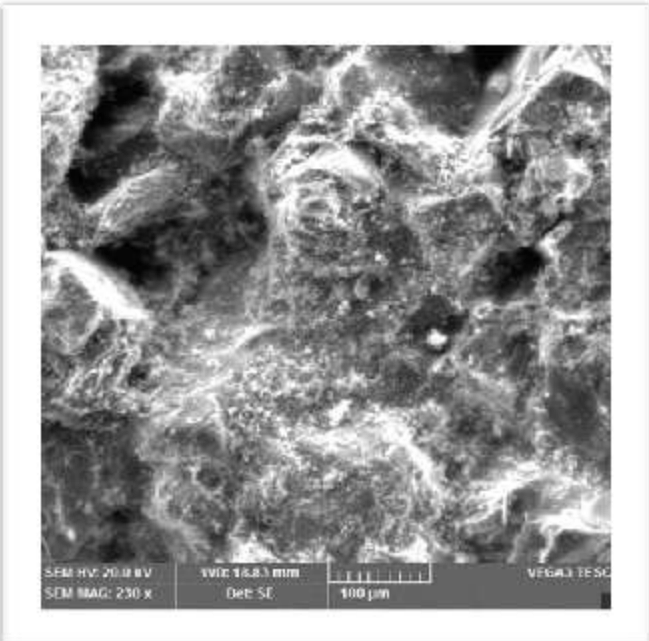


Figure (4.2): SEM picture after mud test for Sample x-1 (Near Wellbore)

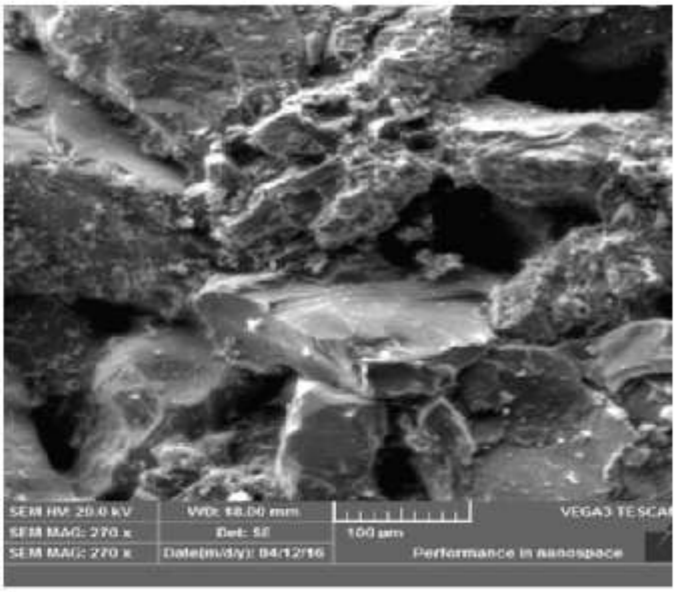


Figure (4.3): Deep Reservoir Sample for x-1 (After Drilling Fluid Test)

From SEM test, which was done before mud test, it becomes clear that the composition of the formation in addition to the pore space. Core labing figures (4.1) and (4.2) it’s very clear that the composition of drilling additives is **invaded the pore space.**

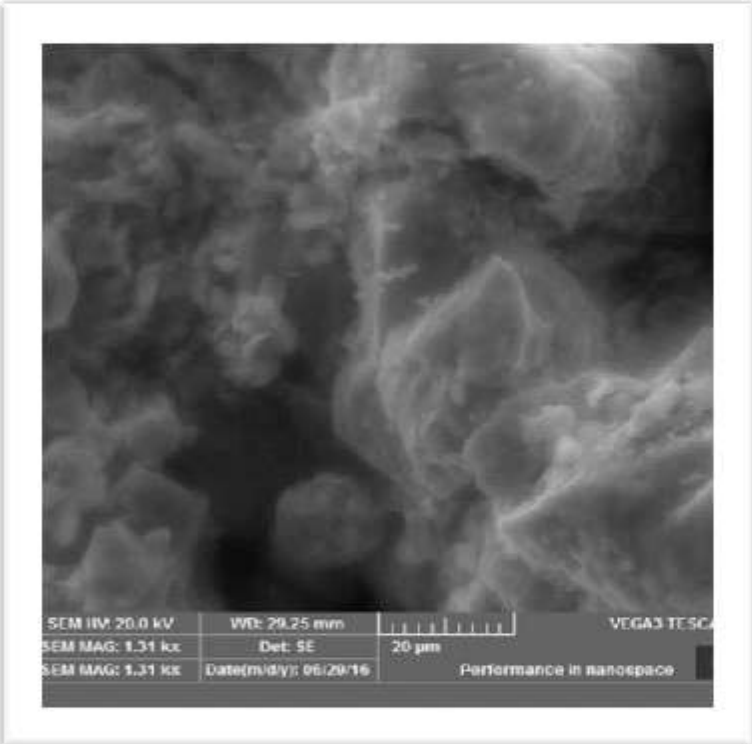


Figure (4.4): SEM Picture before mud test for sample X-2

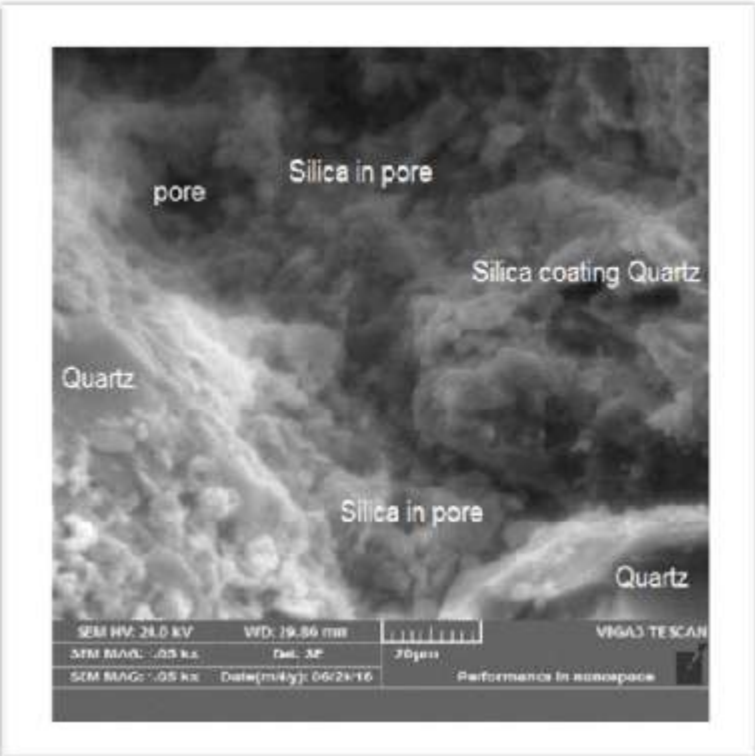


Figure (4.5): SEM Picture for near well-bore sample# x-2 after mud test

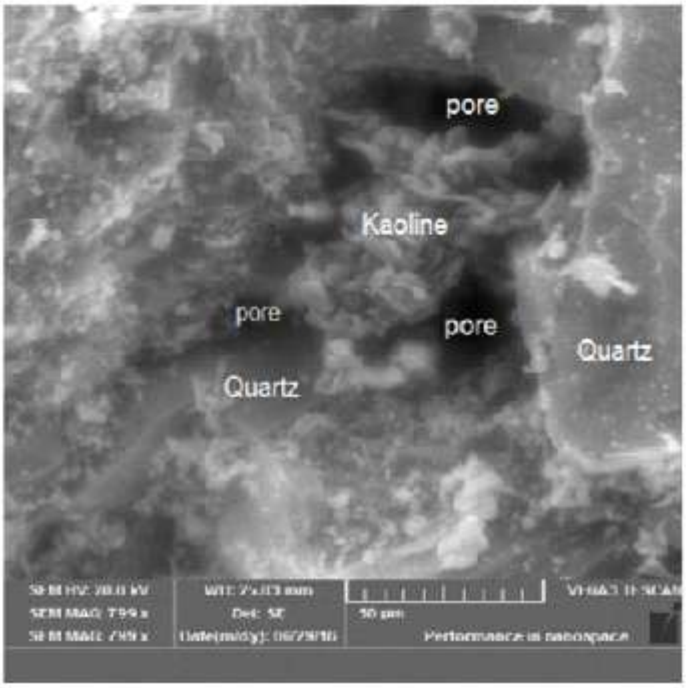


Figure (4.6): SEM Picture for Deep Reservoir sample# x-2 after mud test

From SEM test for sample X-2, which was done after mud test, it t becomes clear that there is a substance in the pore space which is **silica gel and silica coating quartz.**

The thin Sections (Petrography) shown in figures (4.7), (4.8), (4.9), (4.10), (4.11) and (4.12).

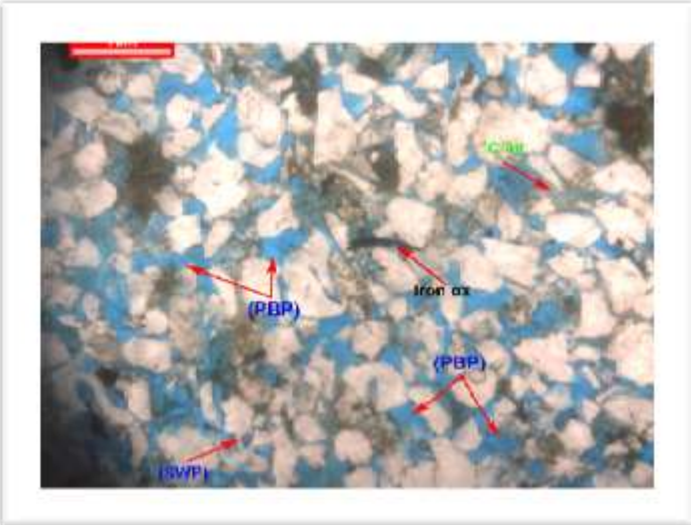


Figure (4.7): Thin Section before test for Model x-1

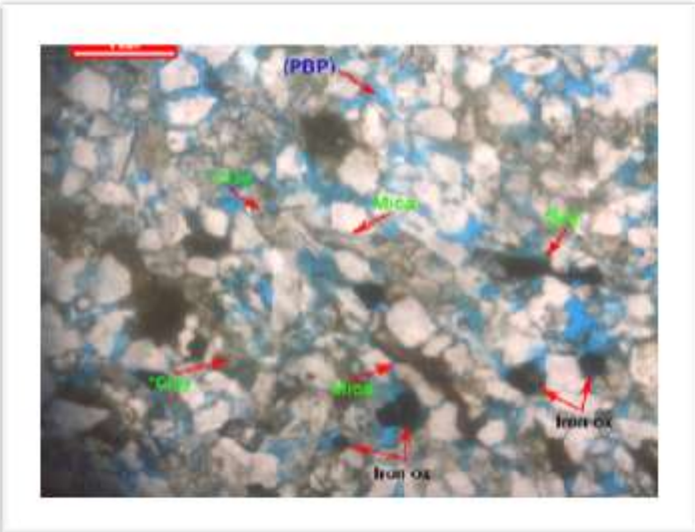


Figure (4.8): Thin Section after test for Model x-1

Figure (4.9): Thin Section of deep reservoir sample for x-1 well after test

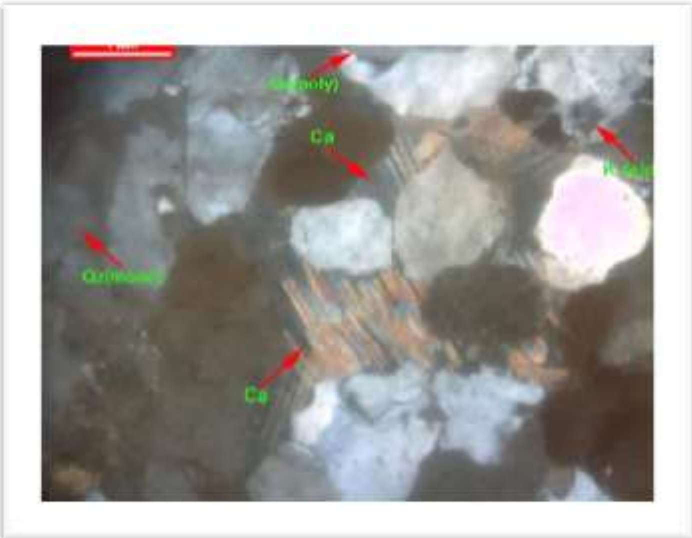


Figure (4.10): Thin Section before test for Model x-2

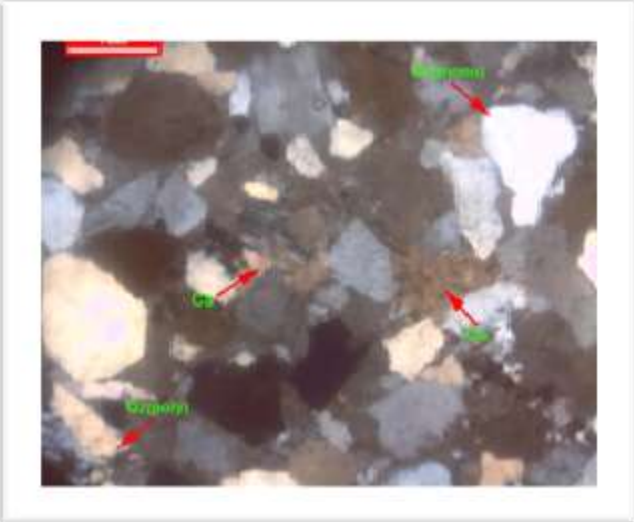


Figure (4.11): Thin Section after test for Model x-2

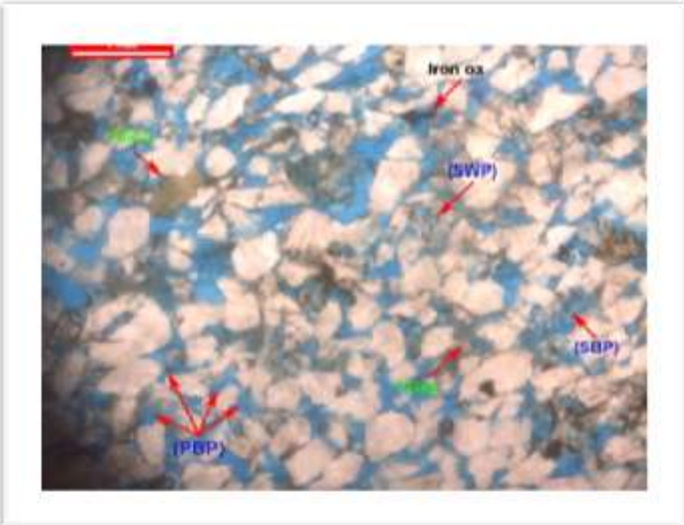


Figure (4.12): Thin Section of deep reservoir sample for x-2 well after test

The figure (4.7) shows the sample under a polarizing microscope before exposure to drilling fluid. 26.6% is the value of the estimated porosity.

The figure (4.8) shows the sample after expose to drilling fluid. By analyzing the slide of rock sample, the estimated porosity is 17.6%.

The figure (4.9) shows the sample. This sample porosity is 18.8%. Note that there is no clear decline in the value of porosity. Because it is not affected by the drilling fluid therefore less precipitation for mud cake in sample pores.

The figure (4.10) shows the sample under a polarizing microscope before exposure to drilling fluid. 21.8% is the value of the estimated porosity.

The figure (4.11) shows the sample after expose to drilling fluid. By analyzing the slide of rock sample, the estimated porosity is 9.2%.

The figure (4.12) shows the sample. This sample porosity is 21.4%. Note that there is no clear decline in the value of porosity. Because it is not affected by the drilling fluid therefore less precipitation for mud cake in sample pores.

Petro physical properties of the selected samples have been measured and reported are tabulated in table (4.4) below

Table (4.7): CT Scanning Petro physical properties

Well	Sample No	Sample depth (m)	Sample diameter (cm)	Sample Length (cm)	Porosity (%)	Permeability (mD)
X-1	6	1549.68	3.84	5.2	26.89	254.58
	7	1550.97	3.89	5.2	24.64	175.75
	8	1557.3	3.88	6.2	24.53	111.85
X-2	10	2696.27	3.80	5.36	17,50	145.41
	41	2727.97	3.80	5.3	16.88	194.04
	47	2729.46	3.82	5.02	18.16	18.16

From the CT scanning, it is obtained the sample's porosity and permeability percentages were reduced.

Table (4.8): Laboratory Formation Damage Tests

	Initial Permeability (mD)	Return Permeability (mD)	PCP %	Ultimate Dynamic Fitrate (cc)	Ultimate Static Fitrate (cc)
x-1	51,4	46,29	13	16	8,1
x-2	35,9	8,47	76	17,64	3,52

Noted a clear **decrease** in the permeability in the **X-1** layer by the percentage of **(PCP 13%)** after the mud test. As well as a significant **decrease** in permeability in the **X-2** layer by the percentage of **(PCP 76%).**

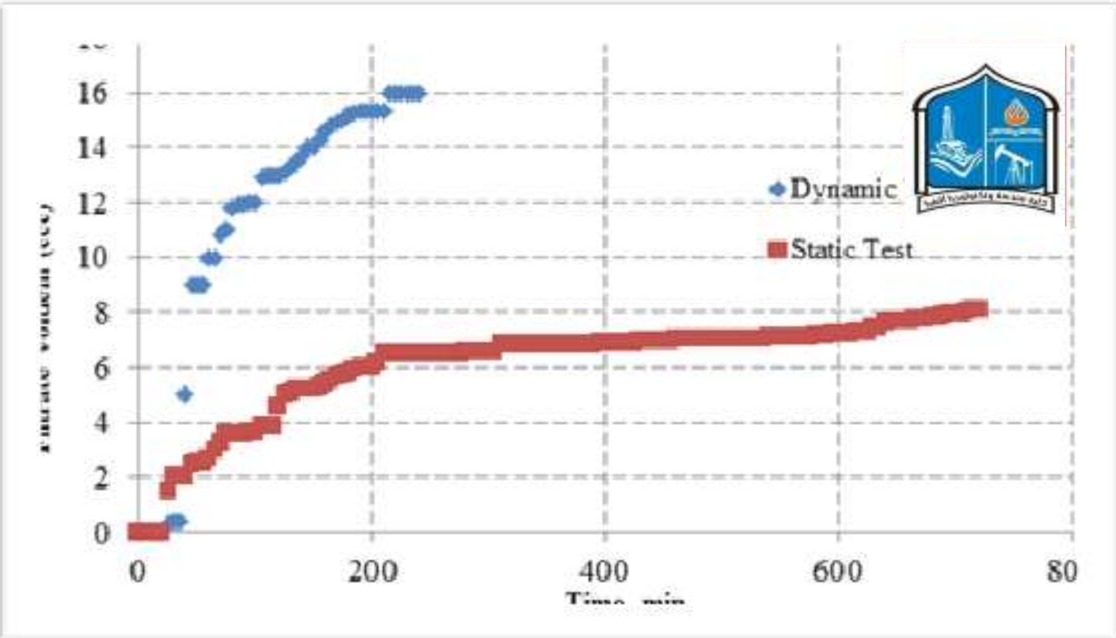


Figure (4.13): Volume of fluid filtrate with time for model X-1

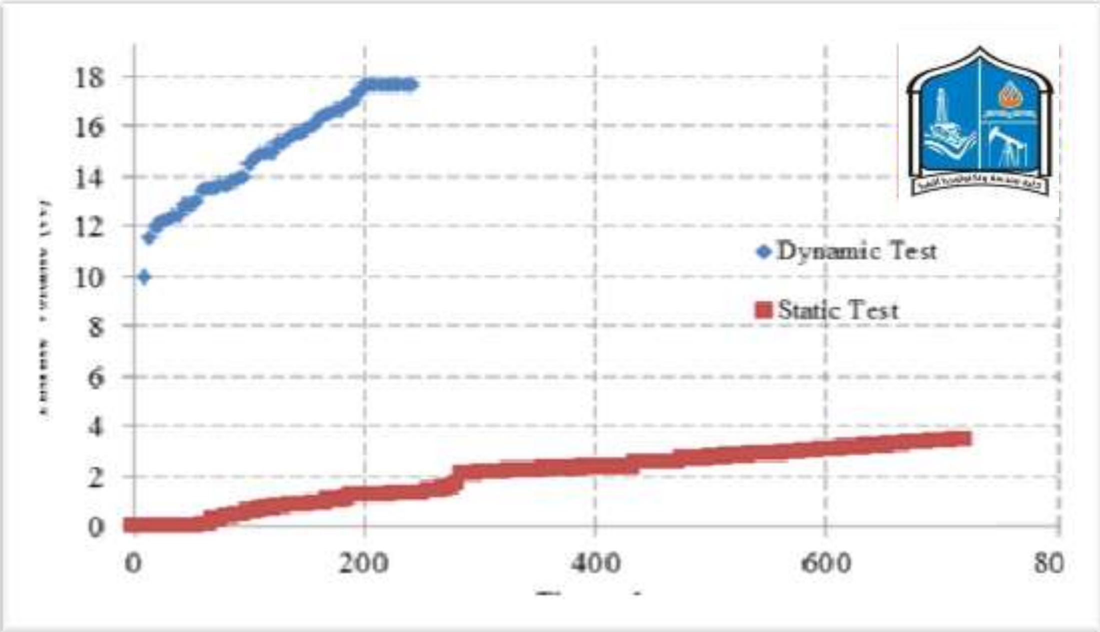


Figure (4.14): Volume of fluid filtrate with time for model x-2

In **dynamic test** case, found that the filtrate volume or fluid loss increases significantly with the passage of time compared with the **static test** as shown in the figures.

CHAPTER 5

Conclusion and Recommendation

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5.1. Conclusion

*Results from the drilling fluid test were observed a clear reduction in permeability values.

This decrease in permeability values was a result of the invasion of the solids and filtrate.   No significant difference in the dynamic filtration was observed as compared to the static filtration

The SEM results showed deposition and plugging of pore throats by drilling fluid and coated quartz grains.

The results of the EDX and XRD showed that this material deposited mainly composed of Silica and although Aluminum which are also a part of clay minerals.

The increase in the proportion clays may be due to the clay migration. It was observed the lack of this material on samples which positioned on deep reservoir area.

High permeable x-1 sandstone cores may result in rapid deposition of the material that forms the mud cake.

Since the permeability of samples are related to pore throat size, lower permeability samples may have smaller pore throat size and are subjected to more pore plugging and thus higher damage is expected.

Static filtration was observed less than dynamic filtration due different rheological behavior of the mud and also possibility formation of flocks with larger sizes in the static condition and more plugging.

5.2. Future works and recommendation

In order to extend the present study and further evaluation of formation damage to either prevent or diagnosis of the problem, following additional research are recommended:

1. The treatment is carried out by forming a process fluid containing an aqueous fluid containing a source of hydrogen fluoride and an inhibitor of amorphous silica precipitation.
2. When the treatment fluid is introduced into the formation, it should be at a pressure lower than the formation crack pressure to facilitate dissolving of the formation materials.
3. The treatment fluid should contain at least about 500 ppm of silicon after at least about 100 minutes have passed after the treatment fluid is introduced into the formation.
4. The amorphous silica inhibitor is a polycarboxylate, polycarboxylic acid, or silane organic or, phosphonate.

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