Republic of Yemen
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الجمهورية اليمنية
الجامعة الإماراتية الدولية
كلية الهندسة وتكنولوجيا المعلومات
قسم هندسة النفط والغاز

EMIRATES INTERNATIONAL UNIVERSITY

FACULTY OF ENGINEERING AND INFORMATION TECHNOLOGY

OIL AND GAS ENGINEERING DEPARTMENT

SELECTION OF THE THERMAL ENHANCE OIL RECOVERY METHOD FOR AL-ROIDHAT HEAVY OIL FIELD IN BLOCK-9

A PROJECT SUBMITED IN PARTIAL FULFILLMENT

OF THE REQUIREMENTS FOR THE DEGREE

OF BACHELOR OF SCIENCE

IN OIL AND GAS ENGINEERING

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SEPTEMBER, 2022

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ABSTRACT

Petroleum represents an important source of energy. The different resources for energy are classified into renewable and non-renewable. Petroleum is the main source of the non-renewable energy where it is found in conventional and non-conventional reservoirs. Conventional oil production is started since the last century with a high oil and gas production using primary and secondary recovery. Most of the current world oil production comes from mature fields. Increasing oil recovery from the aging resources is a major concern for oil companies and authorities. In addition, the rate of replacement of the produced reserves by new discoveries has been declining steadily in the last decades. Therefore, the increase of the recovery factors from mature fields under primary and secondary production will be critical to meet the growing energy demand in the coming years.

Now, the global demand is high compared to the supply from the existing produced fields. The production is declining from the conventional resources, so the production from the unconventional reservoirs is essential to cover the market demand. The unconventional resources are classified as shale oil, shale gas, heavy oil, extra-heavy oil and bitumen. The challenge is to find the best production method that will lead to high production with low cost. The reserves for unconventional resources are estimated by trillions of oil barrels. The primary and secondary recovery methods don't meet with the unconventional resources as recovery enhancement methods, thus, EOR technologies have been proposed to recover the unconventional resources. EOR methods play a key role to meet the energy demand in years to come.

This paper presents a comprehensive review of EOR status and opportunities to increase final recovery factors. Specifically explains the thermal EOR methods and discuss them, the project is focusing on selecting the proper thermal EOR in Al-Roidhat Field Block-9 (Malik) in Yemen. The first goal was to choose the available screening criteria to select the desired thermal EOR method. Taber Screening criteria was found to be the best for the final selection. Hence the Taber was matched with Al-Roidhat field. After selection of the thermal EOR a discussion and researches have been represented, also, some comparisons and calculations have been done following by results available that would explain whether the selected method is favorable or unfavorable recovery method to be applied in the field.

ACKNOWLEDGMENT

Words cannot express our gratitude to our **Dr. YASIN AL-SALEHI** for invaluable patience and feedback. who generously provided knowledge and expertise. Additionally, this endeavor would not have been possible without the generous support from the university.

Also, we would like to thank ourselves for everything, for straggling and studying very hard, for researching and the attendance to collect all data needed to finish that project.

Thank you.

Lastly, we would be remiss in not mentioning our families, especially our parents. Their belief in us has kept our spirits and motivation high during this process.

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LIST OF ABBREVIATIONS USED

CO2	Carbon Dioxide
CSS	Cyclic Steam Simulation
API	American Petroleum Institute
ASP	Alkaline compound, Surfactant and Polymer
EOR	Enhanced Oil Recovery
GOR	Gas Oil Ratio
MEOR	Microbial Enhanced oil Recovery
Md	MilliDarcy
SOR	Steam Oil Ratio
PV	Pore volume
CSI	Cyclic steam injection
MMSTB	Million Stock Tank Barrel
BOBD	Barrel Oil per Day
MBOPD	Thousands of barrels of oil per day
CGS	Centimetre Gram Second
IOR	Improved Oil Recovery
SCF	Standard Cubic feet
PPM	Parts Per Million
PSI	Pounds Per Inch
WEG	Water Alternating Gas
BTU	British Thermal Unit
MMBTU	Million British Thermal Unit
KG	Kilogram
PVT	Pressure Volume Temperature
YOGC	Yemen Oil Gas Company
Gr	Gram
Mol	mole
Bo	Oil Formation Volume Factor
O and **GJ**	Oil and Gas Journal
ΔT	temperature difference = $T_f - T_s$
cP	Centipoise.
Bbl	Barrel.
So	oil saturation, fraction
Ts	steam temperature
TR	initial formation temperature
μ	viscosity
μ_{oc}	oil viscosity at initial reservoir condition
μ_{oh}	**oil viscosity after cyclic steam**
°F	Fahrenheit

°C	**Celsius**
r_w	**well radius**
r_d	**radius of steam**
r_h	**radius of heated zone**
r_e	**drainage radius**
K	**permeability**
K_d	**permeability after steam**
J_h	**productivity index after cyclic steam**
J_c	**productivity index before steam**
Q_{oh}	**flow rate after cyclic steam**
Q	**flow rate before steam**
D	**depth**
h	**reservoir thickness**
H_O	**heat capacity of steam per hour**
t	**time**
M_r	**reservoir heat capacity**
hr	**hour**
d	**day**
ΔA	**alternative area**
AA	
MSTB	**thousand stuck tank barrel**
MMBO	**million barrel of oil**

CHAPTER ONE

1. INTRODUCTION

Petroleum Industry is considered as one of the major energy resources in world, as in the last decades, the demands of petroleum and its derivatives has become increasing, although the hydrocarbons production is not enough economically, due to that most of hydrocarbons is extracted from light hydrocarbons zones, which are limited. Another solution is available for that issue, which is extracting heavy oils and sand bitumen, which is not extracted in conventional methods, due to the capital expense that makes the industry too uneconomic. Heavy crude oil is a kind of formation oil which doesn’t run easily in the reservoir due to its higher density and viscosity compared with light oil, also the heavy oil is characterized as its heavier composition and molecular weight. Heavy crude oil is defined as any kind of liquid petroleum with gravity less than 20 API, and a reservoir viscosity range of 50-5000 cp. New technologies and methods has been presented currently, these technologies are presented for enhancing oil recovery by producing heavy oils and sand bitumen economically. One of the major treatments and enhancing methods for heavy oils is Enhance Oil Recovery (EOR), this method Enhance heavy oils recovery either thermally or chemically based on the mechanism and the properties of the reservoir.

In this project, we'll study the reservoir characteristics and the properties of the unconventional fluid contained in AL-Roidhat in block-9, in order to evaluate the optimum economic recovery method.

1.1 Aim and Objectives

1.1.1 Aim of The Project

The project aims to enhance the oil productivity in Al-Roidhat Block-9 by selecting the optimum thermal EOR recovery method, and discuss the effectiveness of the chosen method.

1.1.2 The Project Objectives

1. Defining the geological history of Al-Roidhat field in Block-9.
2. Studying the reservoir characteristics and the nature of fluid contained with its properties.
3. Define the thermal EOR methods and select the suitable one to be applied in the field.
4. Finding the possible incremental productivity index after applying the thermal EOR method.

1.2 Problem Statement

Heavy oil production has many restrictions which make it uneconomic to be produced. Most of heavy oil reservoir has poor movability, wherefore the oil is hard to be transmitted into the well, and then to the surface which is the first difficulty that must be solved by selecting appropriate recovery method. The heavy oil with its components is complicated in comparison with the conventional oil, which is another challenge encountered in heavy oil production that we should recover by providing a special processing able to produce valuable products from the crude oil. These issues will be our study about block-9(**Al-Roidhat**) in this project.

1.3 Research Question

How to improve the oil productivity of Al-Roidhat field in Block-9 by selecting the proper thermal EOR method?

1.4 Geological Review

The geology of Yemen is diverse extending from Precambrian basement rocks to recent sediments. It includes metamorphic rocks, that formed during Archean Proterozoic time (**Fig. 1.1**). Yemen composes part of the Arabian Shield within the larger framework of the Arabian-Nubian Shield. The Precambrian Arabian Shield is in the western part of the country and an extensive and thick cover of Phanerozoic sub horizontal sediments to the east.

The India/Madagascar and Africa separation worked out in late Jurassic caused extensional tectonic in Yemen. It is remarkable to notice that there is no volcanic activity related to this event. But remarkable feature is generation of graben/horst structures that shaped new topographies for sediments accumulation especially in east and southeast of Yemen. Seismic images, well data, and field observations from the Mesozoic basins of Yemen indicate that the rifting started during early Kimmeridgian in the western part, during middle Kimmeridgian–Lower Tithonian in the central part, and shortly later in the eastern parts of Yemen. Subsequent northeastward separation of the Indian plate is reflected in the easterly and southerly propagation of basin subsidence and sediment fills in Yemen during Tithonian-Valanginian times. The geology of Yemen has influenced by a complex tectonic history in the first event. It is evident from the various terranes with various origin (continental and island arc). During the second event of tectonostratigraphic renewed tectonostratigraphic activity without related volcanisms activity produced various depositional environments. Transgression and regression have been the significant controlling factor for sedimentary and patterns.

Age			Group West	Group East	formation West	formation East	Lithology	
Cenozoic	quaternary	Holocene/ Pleistocene	Quaternary Deposits				Sands, gravel, loam, loess, clay, conglomerates, sabkha deposits, marine shell and reef deposits	
			Quaternary Basalts				Basalts, tuffs, agglomerates, trachy-andesite, pumice	
	Tertiary	Oligocene/ Miocene	Jezan group	Shihr group	Baid	Irqah	Shales, limestones,	Gravelly conglomerates
						Fuwwah		Conglom & fossiliferous limestone
		Miocene/ Eocene	Tertiary Intrusive				Granites	
			Yemen Volcanics				Basalts, trachy-ndesites, rhyolites, pyroclastic rocks	
		Eocene		Hadramawt group		Habshiya	Limestones, marls, shales, gypsum	
						Rus	Gypsum, anhydrite, dolomitic limestones	
						Jiza	Shales, fine-grained limestones	
		Paleocene				Umm-Er-Radhuma	Massive marly & dolomitic limestones.	
			Tawilah group		Medj-Zir		Hard argillites, cross-bedded bioclastic sandstones	
Mesozoic	cretaceous				Twailah sandstone	Sharwayn	Yellow sandstones (Kawkaban member), dark red sandstones (Shibam member), and white clayey sandstones (Thula member)	Sales, limestone, sandstones
						Mukalla		Fine/medium sandstones
						Fartaq		Calcarenites
						Harshiyat		Sandstones with conglomerate intercalations
						Qishn		Calcarenites, limestone
	Jurassic		Amran limestone		Ahjur		Bituminous marly and sandy mudstones	
					Nayfa		Limestones and dolomites	
					Madbi	Sabatayn	Marls and limestones	Evaporates and shales
					Shuqra		Limestones	
	Lower Jurassic		Kohlan group		Kohlan Sandstone		Sandstones with conglomerate intercalations	
Paleozo	Permian				Akbra Shale		Laminated mudstones, siltstones, shales	
	Cmbo-ordovician		Wajid group		Wajid Sandstone		Cross-bedded sandstones and coarse siltstones	
Pc.	Precambrian		Precambrian basement				Igneous rocks, metamorphic rocks, metasediments	

Fig 1.1: The Stratigraphy of Yemen

One of the wide exposures of sedimentary basins in Yemen was in Mesozoic and Cenozoic units. Sayun-Masila basin is one of the Mesozoic basins in Yemen. It is formed as a result of a rift-basin like linked with the Mesozoic break up of Gondwanaland, and due to the evolution of the Indian ocean during the Jurassic and cretaceous. Sayun-Masila basin has several different interpretations due to its complex structural morphology. Common agreement is that Sayun-Masila basin has a western area with NW-SE orientation parallel with Sabatayn basin. Another extension to the north is the Sir basin. To the east the Sayun-Masila basin is oriented more (east-west) and is broadly symmetric with intrabasin high known as Masila terrace. Regionally in Yemen and locally in Sayun-Masila basin, the Jurassic and lower cretaceous strata have reflected the breakup of Gondwanaland and basin creation formed by rifting during the early cretaceous and late Jurassic period, also rifting of Aden and red sea throughout tertiary age. Rifting caused series of NW-SE and E-W trending major faults basin bounding the Sayun-Masila basin (**Fig. 1-2**). This basin has been affected structurally by many normal faults, also folds (anticline and syncline) were present.

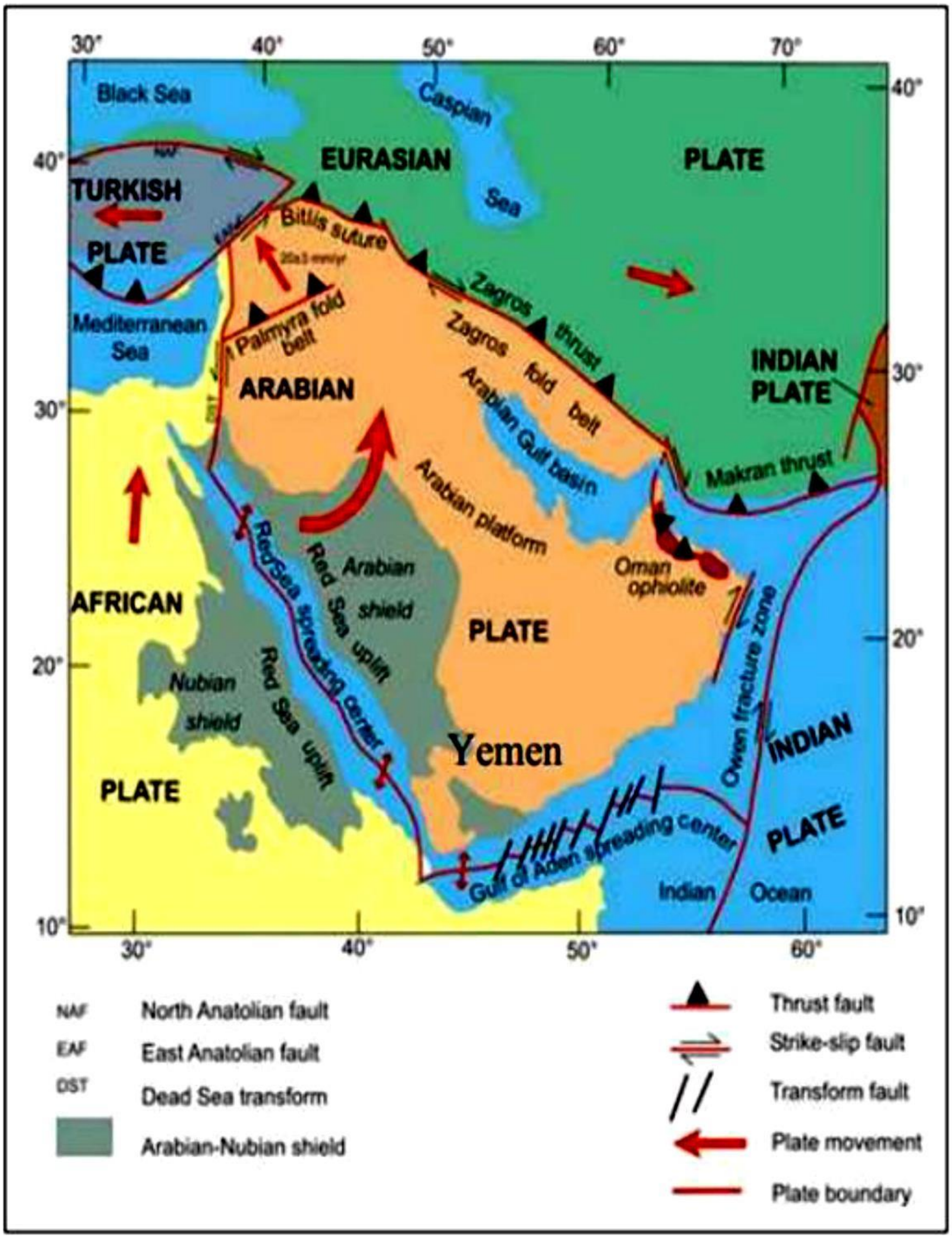

Fig 1.2: Tectonic setting of Arabian shield and Nubian shield

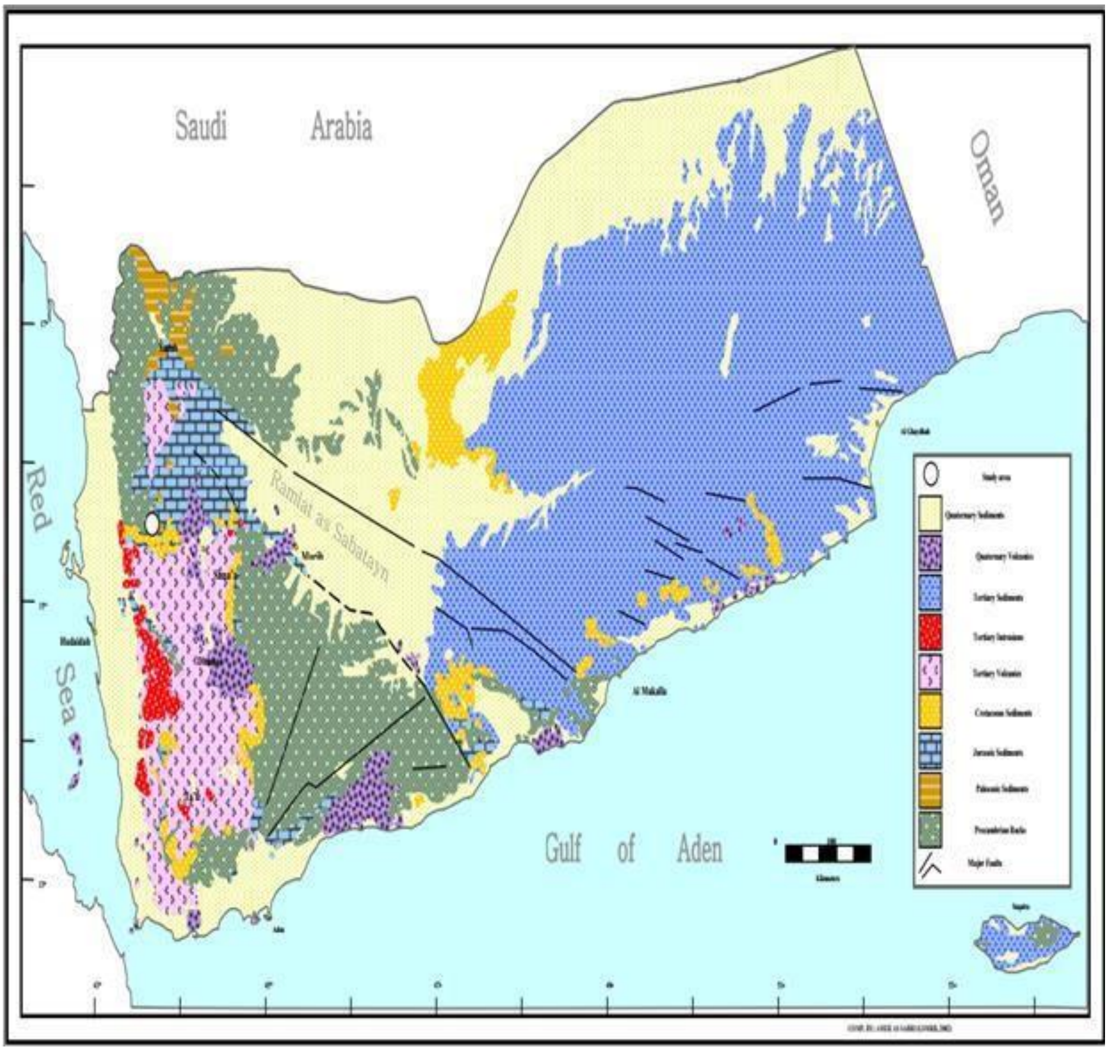

Fig 1.3: Simplified Geological map of Yemen

1.5 Stratigraphy of Masila Basin:

1. **The Basement**: Pre Cambrian rocks, consist of metamorphosed Pre-Cambrian sediments to lower Cambrian. Also, it contains granite and diorite rocks.
2. **Kuhlan Formation**: Jurassic sequence (middle-late). It is clastic with local basement topography. It includes fluviatile and arkosic red beds. It contains siltstone, sandstone, conglomerate and limestone.
3. **Shuqra Formation**: upper Jurassic age, it is neurotic limestone rich with fossiliferous marls. Also, there exist lime-mudstone, wackestone and grain stone.

4. **Madbi Formation**: it is a syn rift sediments deposited in the late of the Jurassic age. The lithofacies reflects the marine environment. Madbi Formation consist of two members: -

a. The lower member: is argillaceous limestone and sandstone and forms a good reservoir in some oil fields in Masila basin.

b. The upper member: composed of laminated organic shale, mudstone and calcareous sandstone. This member is prolific source rock in Masila province.

5. **Naifa Formation**: this formation consists of silt and dolomitic limestone and lime-mudstone with wackestone.

6. **SAAR Formation**: this formation has deposited during transgression in the early cretaceous time. It consists of limestone and dolomite with mudstone and sandstone intercalations.

7. **Qishn Formation**: Qishn formation ages between Barremian and Aptian.

a. Qishn Formation Transition: Lower Aptian age. Shale, calcareous shales, and occasional sandstones constitute this interval. The unit directly overlies the Qishn Carbonate and forms the uppermost part of the hydrocarbon seal for the reservoir sandstones of the Qishn Clastics

b. Qishn Formation Carbonate: Barremian to Lower Aptian age. Predominantly argillaceous limestones with interbedded calcareous shales. This unit is a regional hydrocarbon seal for the reservoir sandstones of the underlying Qishn Clastics.

c. Upper Qishn Formation Clastics: Barremian age. The major hydrocarbon-bearing reservoir of **Masila block** with sandstone and claystone/siltstone interbeds. Thin coals, limestones and occasional anhydrite may be present. The sandstones are mainly well sorted, sub-angular to sub-rounded and generally poorly consolidated with scattered well-consolidated stringers. The loose grains indicate good porosity, and this unit is recognized to be the primary hydrocarbon objective. The upper Qishn sandstones of the Qishn Formation have been stratigraphically subdivided by petroleum geologists into three informal units: an upper S1, a middle S2, and a bottom S3. S1 refers to the first sandstone encountered below the Qishn Carbonates Member, followed by the S2 and S3. The S1 is subdivided into S1A, S1B, and S1C, based on the presence or absence of non-reservoir (carbonate and shale) lithology's

d. Lower Qishn Formation Clastics: Barremian age, Finer grained than the Upper Qishn Clastics. Mainly siltstones and shales; interbedded sandstones are usually poorly sorted, and tight. There are some porous sands, though only locally does this unit constitute a reservoir. The Lower Qishn Formation is divided into two informal units: an upper LQ1 and lower LQ.

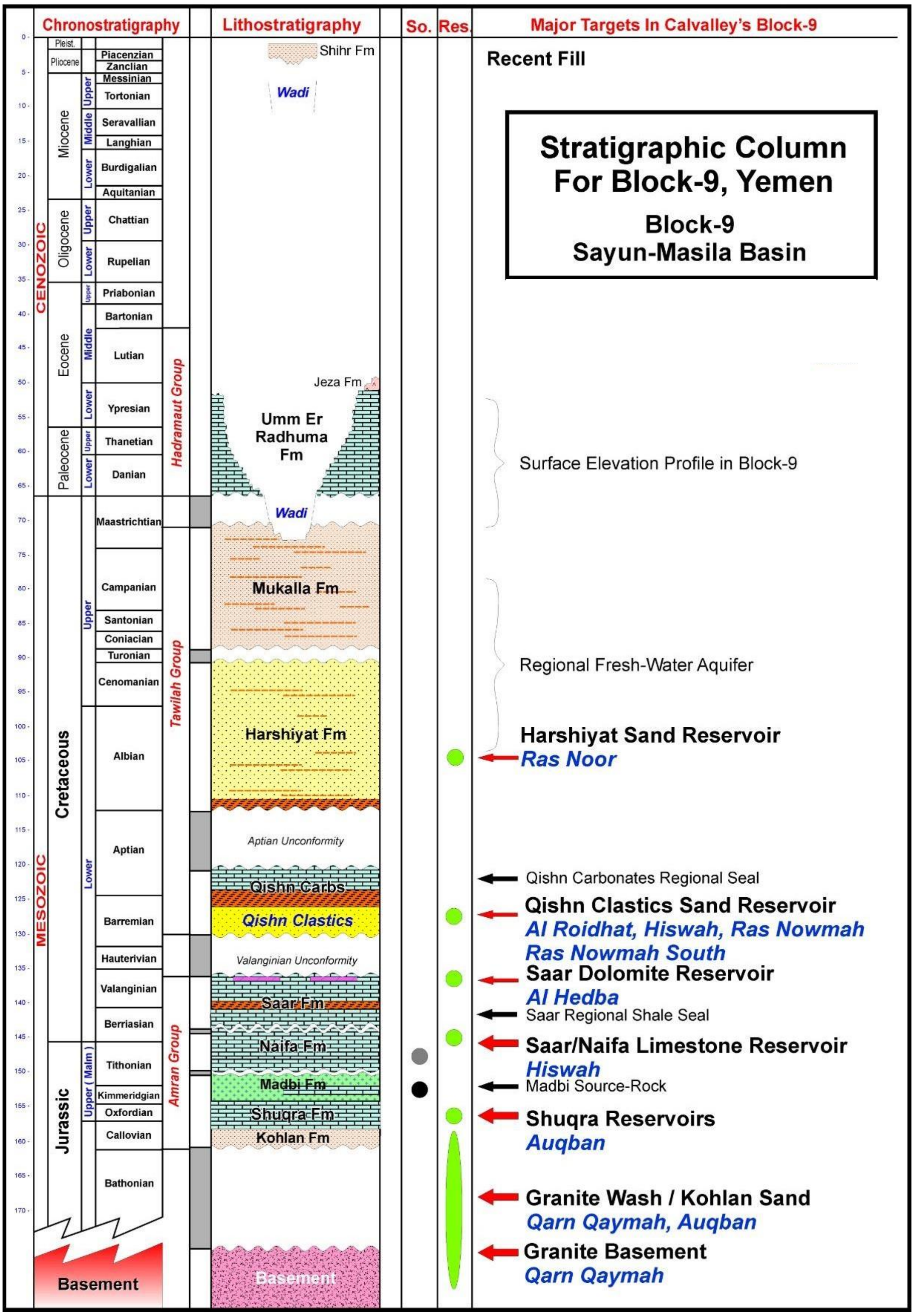

Fig 1.4: The Geological Column of Sayun-Masila Basin

1.6 Block-9 (Malik)

Block 9 is an exploration and production block located in the province of HADRAMUT, Republic of Yemen, about 350 kilometers north-east of Yemen capital, Sana'a.

The block, which is located within the Sayun-Masila basin, has an area of 2,234 square kilometers, in which some of its area has previously been explored.

On 25 August 2005, the government of Yemen has granted the construction license for this block for the period of 20 years.

The license also states that the holders of participating interest of this block (the contractor) has the right to negotiate for an extension of another 5 years after 2025.

The estimated gross 1P reserves of block 9 is approximately 254.81 MMBO (as of 1 May 2012) and is envisaged to produce up to approximately 10.68 MBOPD. The block operated by Calvalley petroleum LTD and participating interest MEDCO YEMEN Malik LTD, hood oil and YOGC.

1.6.1 Block -9 (Malik) consists of five fields:

- Hiswah field.
- Ras Nawmah field.
- Qarn Qymah field.
- Auqban field.
- Al-Roidhat field.

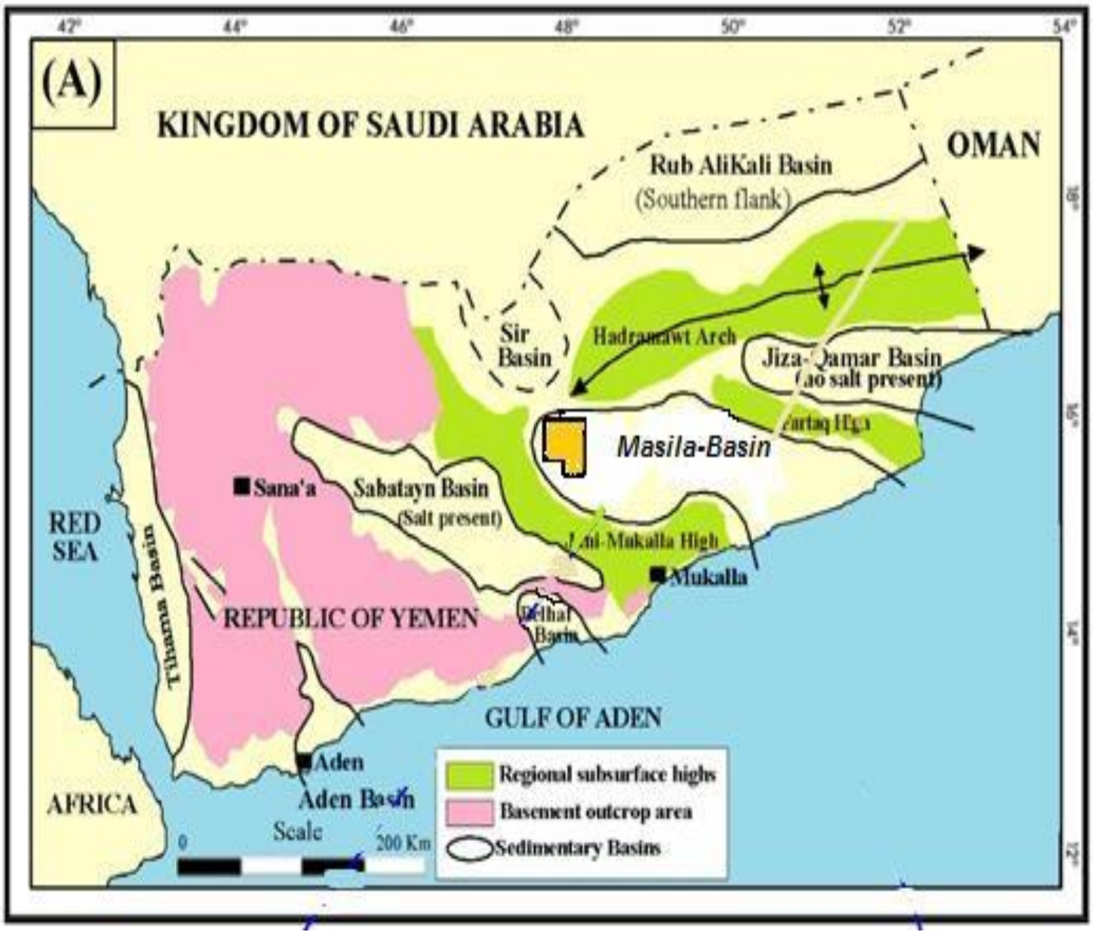

Fig 1.5: concession map Masila basin in Yemen

1.6.2 Al-Roidhat Field

The field is located in Wadi AMD on Malik (Block-9) in eastern Yemen. It's medium in size with a productive area of approximately 1672 acres with three reservoirs, the S1, S2 and S3. The field was discovered in August 2003 by an exploration well. Current development and production activities are focused on S1 sand reservoir, mainly due to the more favorable reservoir characteristics compared to the S2 and S3 reservoir and to avoid excessive water production. A total of nine wells were drilled, but only six of them have been producing oil.

The field is characterized with (**14.2-15** API Gravity), with a low solution GOR of (**1.7** Scf/bbl), initial oil viscosity is **420** cp and initial pressure of about **1140** psi, it's naturally producing using the aquifer as an energy, even though, this aquifer poses a disadvantage due to high increase in water cut. Over time the oil production keeps decreasing and a development plan is required to optimize the oil recovery.

Table 1-1 Al-Roidhat Field

Exploration Date	Start production date	Number of drilled well	Initial pressure (psi)
August, 2003	1,December, 2009	9	1140

1.6.3 Production History

Oil production started in September 2007 with initial production rate in the range of 250-400 bbl/day for each of wells that produced oil in the field. The producing wells showed a little water production during the initial stages but in the end, water production begins to increase after a few of months. The total field production rate reached peak of production of 354 MSTB during 2012. The initial hydrostatic reservoir pressure in the reservoir is 1140 psi at a datum of 1072 meters. The relatively small decline in reservoir pressure demonstrates the great strength of the aquifer. This field has been in production period and has been closed for 8 years up until the end of the year 2020.

Table 1-2 Oil Stock Details of Al-Roidhat Field

Oil reserve	Reserves (MMBO)	Recoverable (MMBO)	Produced until May 2012(MMBO)	Remain (MMBO)
1P	55.24	11.04	0.08	10.96
1P+2P+3P	175.59	35.12	0.08	35.04

CHAPTER TWO

2. Literature Review

2.1 Introduction

Crude Oil plays an important role in the current and future energy markets, so the discovering and production for hydrocarbon reservoirs is necessary due to rise demand of this energy as the world growing and developed. Oil divided to several kinds as differences of criteria. those kinds produced at low or high cost and differences technology with respect the reservoir, fluid and rock properties.

Oil, petroleum, Black gold and such other names are used by the public which indicate the crude oil found under the ground as a natural source of energy. Most people "specially those who aren't involved in oil industry" think of oil as a single substance or homogenous product from similar environment or circumstances from the subsurface. Actually, crude oil is a subsurface product that is applied to so many variables in (origin, characteristics, properties, compounds, etc.) which make crude oil has more than one type. Simple classification of crude oil is:

Class A: it is light oils can penetrate porous surfaces and are clear or almost clear. They have a strong odor and flammability. Since they are thin and highly fluid, they mix well with other liquids. Most high-quality light crude oils and refined petroleum products fit into this class.

Class B: this non-sticky oil is thicker than those in Class A and have a waxy feel. They adhere better to porous surfaces when in warm temperatures such as Paraffin.

Class C: it has density near that of water, these oils do not usually penetrate porous surfaces, but they do sink in water. They are sticky, similar to tar, and usually black or brown. Medium and heavy crude oils including residual fuel oils fit into this class.

Class D: This oil is not fluid, so they do not penetrate porous surfaces and do not flow freely. They can become more fluid when heated and are usually made up of heavy crude oils or those with high paraffin content.

Another general classification of crude oil is:

1. Conventional oil: this type is consumed. It has more interest and great space in oil industry investments due to its ease of production, processing and transportation. Also, it has a good characteristic which plays a major role in its refinery products. Another important aspect is the economic side that has a high possibility of profit and a wide space to invest.

2. Un conventional oil: this oil which dominates the highest volume of reserve which exceeds the conventional oil. For some reasons, un conventional oil hasn't been developed as much as conventional oil. The little interest relates directly to the opposite variations it has against the conventional one such as production, processing, etc.

Fig. 2.1: shows a chart of the world's total remaining oil reserves. The heavy, extra heavy oils and bitumen are expected to make up 70%. This number underlines the increasing importance of heavy oil production going forward, as conventional supplies are decreasing

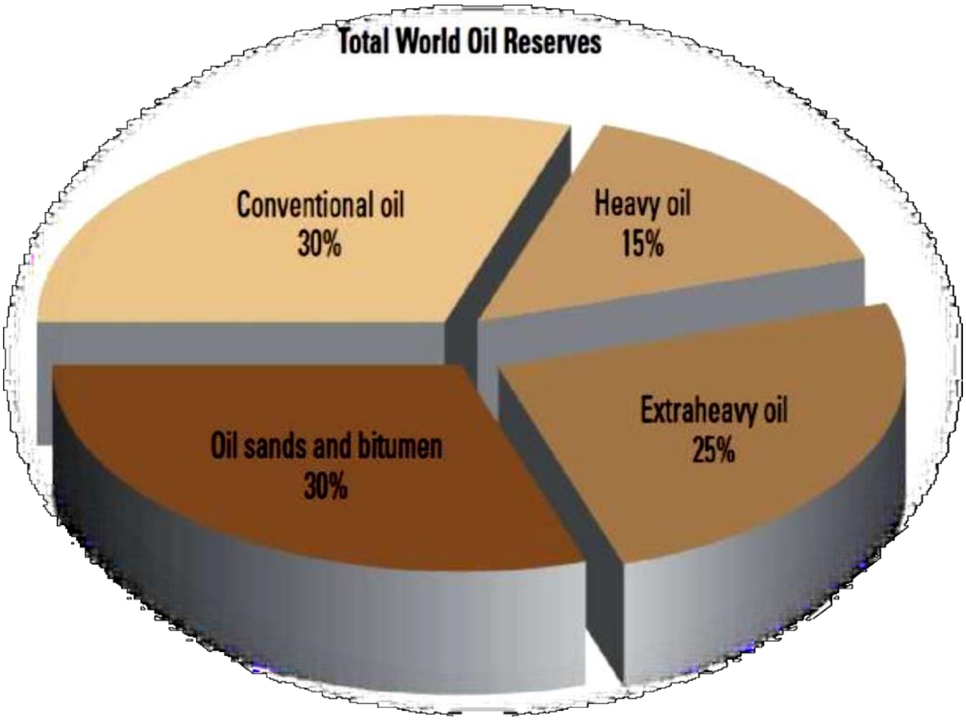

Fig 2.1: Distribution of Total World Oil Reserves by Classification Oilfield Review, (2006)

2.1.1 Definition of Heavy Oil

Compared with conventional oil, heavy oil has reduced mobility; it is termed as heavy oil because it has higher specific gravity and density along with viscosity when compared with the conventional oil.

Heavy crude oil is described as dead oil (gas-free oil) when its density is below 21°API and its viscosity is between 100 and 10,000 centipoise (cP) at original reservoir temperature. Dead oil was chosen because it is easily handled and because standardized analytical techniques were available to measure the properties.

Heavy oil is an oil resource that is characterized by high viscosities (i.e. resistance to flow) and high densities compared to conventional oil. Most heavy oil reservoirs originated as conventional oil that formed in deep formations but migrated to the surface region, where they were degraded by bacteria and by weathering and where the lightest hydrocarbons escaped.

Heavy oil is a type of crude oil characterized by an asphaltic, dense, viscous nature (similar to molasses), and its asphaltene (very large molecules incorporating roughly 90 percent of the sulfur and metals in the oil) content. It also contains impurities such as waxes and carbon residue. Hence, heavy oil requires additional processing (upgrading) to become a suitable refinery feedstock for a normal refinery.

Although the upper limit for heavy oil is 22° API gravity with a viscosity of 100 cp (centipoise).

2.1.2 Petroleum, Heavy Oil, And Tar Sand Bitumen

2.1.2.1 Petroleum

Petroleum is a chemical combination. to define petroleum and heavy oil on the basis of a single property. While this may be suitable for a general understanding, it is by no means accurate and does not reflect the true nature of petroleum or heavy oil or the characterization of the material. Unfortunately, this form of identification or differentiation is a product of many years of growth and its long-established use, however general or inadequate it may be, is altered with difficulty, and a new term, however precise, is adopted only slowly.

Petroleum is a naturally occurring mixture of hydrocarbons, generally in a liquid state, which may also include compounds of sulfur, nitrogen, and oxygen metals and other elements. Thus, petroleum and its equivalent term crude oil cover a wide assortment of materials consisting of mixtures of hydrocarbons and other compounds containing variable amounts of sulfur, nitrogen, and oxygen, which may vary widely in specific gravity, API gravity, and the amount of residuum. Metal-containing constituents, notably those compounds that contain vanadium and nickel, usually occur in the more viscous crude oils in amounts up to several thousand parts per million and can have serious consequences during processing of these feedstocks. Because petroleum is a mixture of widely varying constituents and proportions, its physical properties also vary widely and the color varies from near colorless to black.

Because there is a wide variation in the properties of crude petroleum and heavy oil, the proportions in which the different constituents occur vary with the origin and the relative amounts of the source materials that form the initial proto petroleum as well as the maturation conditions. Thus, some crude oils have higher proportions of the lower boiling components, and others (such as heavy oil and bitumen) have higher proportions of higher boiling components (asphaltic components and residuum).

Petroleum is typically recovered from the reservoir by the application of primary and secondary recovery techniques whereas heavy oil, although under certain circumstances recoverable by primary and secondary recovery techniques, typically requires the application of tertiary recovery techniques for more efficient recovery of the oil.

2.1.2.2 Heavy Oil

Heavy oil is a denser combination, it is type of petroleum that is different from conventional petroleum insofar as it is much more difficult to recover from the subsurface reservoir. These materials have a much higher viscosity (and lower API gravity) than conventional petroleum, and recovery of these petroleum types usually requires thermal stimulation of the reservoir.

However, heavy oil is more difficult to recover from the subsurface reservoir than conventional or light oil. A very general definition of heavy oils has been, and remains based on, the API gravity or viscosity, and the definition is quite arbitrary although there have been attempts to rationalize the definition based upon viscosity, API gravity, and density.

The term heavy oil has also been arbitrarily (but incorrectly) used to describe both the heavy oils that require thermal stimulation of recovery from the reservoir and the bitumen in bituminous sand (tar sand) formations from which the heavy bituminous material is recovered by a mining operation.

2.1.2.3. Extra Heavy Oil

Extra heavy oil is a nondescript term (related to viscosity) of little scientific meaning. While this type of oil may resemble tar sand bitumen and does not flow easily, it is generally recognized as having mobility in the reservoir compared to tar sand bitumen, which is typically incapable of mobility (free flow) under reservoir conditions.

2.1.2.4. Tar Sand Bitumen

For reference and in order to clarify the terms petroleum (crude oil) and heavy oil, the term bitumen includes a wide variety of reddish brown to black materials of semisolid, viscous to brittle character that can exist in nature with no mineral impurity or with mineral matter contents that exceed 50% by weight.

Crude bitumen is an extremely viscous hydro carbonaceous material (it is not pure hydrocarbon in nature) that will not flow in the deposit unless heated or diluted with low boiling liquid hydrocarbons, such as naphtha. It is frequently found filling pores and crevices in sandstone, limestone, or argillaceous sediments, in which case the organic and associated mineral matrix is known as rock asphalt.

The expression tar sand is commonly used in the petroleum industry to describe sandstone reservoirs that are impregnated with a heavy, viscous black crude oil that cannot be retrieved through a well by conventional production techniques.

By inference, conventional petroleum and heavy oil are recoverable by well production methods (i.e., primary and secondary recovery methods) and by currently used enhanced oil recovery (EOR) techniques.

However, the term tar sand is actually a misnomer; more correctly, the name tar is usually applied to the heavy product remaining after the destructive distillation of coal or other organic matter.

Current recovery operations of bitumen in tar sand formations have been focused predominantly on a mining technique, but thermal in situ processes are now showing success.

Although the word tar is descriptive of the black, heavy bituminous material, it is best to avoid its use with respect to natural materials and to restrict the meaning to the volatile or near-volatile products produced in the destructive distillation of such organic substances as coal and biomass. In the simplest sense, pitch is the distillation residue (the nonvolatile constituents) of various types of tar.

Thus, alternative names, such as bituminous sand or oil sand, are gradually finding usage, with the former name (bituminous sands) more technically correct. The term oil sand is also used in the same way as the term tar sand, and these terms are used interchangeably throughout this text.

Bituminous rock and bituminous sand are those formations in which the bituminous material is found as a filling in veins and fissures in fractured rocks or impregnating relatively shallow sand, sandstone, and limestone strata. These terms are, in fact, the correct geological description of tar sand. The deposits contain as much as 20% bituminous material, and if the organic material in the rock matrix is bitumen, it is usual (although chemically incorrect) to refer to the deposit as rock asphalt to distinguish it from bitumen that is relatively mineral free.

2.1.3 Origin and Occurrence Heavy Oil

2.1.3.1 The Initial Formation of Heavy Oil

Heavy oil is formed from raw organic materials by the influence of temperature and pressure, which in turn relates to the sediment thickness that covers the rocks on the one hand and the development of sedimentary basins on the other, where the organic materials gradually turn into ordinary oil and then into light oil and gas, and that over a long period of time. The presence of raw organic materials explains the presence of viscous oil concentrations that remained in the initial rocks and did not reach the stage of formation of light oil or that it migrated as a result of tectonic factors during the transformation phase and gathered in the nearby reservoirs.

2.1.3.2 The Secondary formation of heavy oil

There are secondary factors that may contribute to the process of forming heavy oil:

1. The impact of aerobic bacteria or sulfur: found in water source surface or groundwater, where allows aerobic bacteria active activity contributes to the conversion of light oil to heavy and that at temperatures below the required.

2. Effect of surface water moving water: As this water causes the washing of light materials commensurate with the degree of dissolution and that when filtered in the layer and contact with oil, which leads to a decrease in light materials and increase the proportion of asphalt and heavy materials in the reservoir and thus increase the viscosity of the residual oil and weight.

3. Natural separation of oil from its components: The natural migration of oil in different stratified rocks allows the passage of gas and light materials and leaves heavy materials sediments lead to a good closure prevents the continuation of oil migration.

4. Formation of asphalt: Asphalt deposition occurs during the migration of gas and light materials or during one of the stages of oil formation, and these sedimentary asphalts cannot be distinguished on the natural form of asphalt resulting from the transformation of organic materials.

2.1.4 The Presence of Heavy Materials in Oil

The existence of such materials depends on many factors including:

The properties of the oil produced, the thermodynamic properties of the layer, the hydrodynamic conditions of the layer, the geological and physical properties of the layer, the method of investment. The most important of these factors is the specifications of the oil produced and the thermodynamic properties of the layer. During the change of the thermodynamic properties of the layer the asphalt and paraffin materials can accumulate at the bottom (leading to reduced permeability) Also in equipment that has downstream lines and stations, this sedimentation problem can appear in mechanical wells and on poor self and lead to a lower oil production rate. Below we show the specifications of both of these materials:

Paraffin Materials

It consists of a crystalline form and its average partial weight (300_400) gr/mol and the degree of fusion (-50-60), They are characterized by good dissolution in aromatic hydrocarbons. (Kerosene, condensate) is practically insoluble in hydrocarbons.

Resin Materials

The partial weight ranges (450-1500) gr/mol. And the density is close to the one and has rubber properties and is high viscosity, dark color.
And soluble in light and aromatic hydrocarbons.
And non-degradable in acids and alkali while heated in the air to (100-150 C) turn into asphalt.

Asphalt Materials

The partial weight ranges (1500-10000) gr/mol. Not soluble in light hydrocarbon compounds but soluble in aromatic compounds.
The density is greater than one. While heated to a temperature higher than (300C) it does not melt but turns into coal. During heating, the presence of sulfuric acid hardens and transforms into carbon, not soluble even in aromatic compounds.

2.1.5 Heavy Oil Properties

Petroleum is perhaps the most important substance consumed in modern society. It provides not only raw materials for the ubiquitous plastics and other products, but also fuel for energy, industry, heating, and transportation. From a chemical standpoint, petroleum is an extremely complex mixture of hydrocarbon compounds, with minor amounts of nitrogen-, oxygen-, and sulfur-containing compounds as well as trace amounts of metal-containing compounds.
The fuels that are derived from petroleum supply more than half of the world's total supply of energy. Gasoline, kerosene, and diesel oil provide fuel for automobiles, tractors, trucks, aircraft, and ships. Fuel oil and natural gas are used to heat homes and commercial buildings, as well as to generate electricity. Petroleum products are the basic materials used for the manufacture of synthetic fibers for clothing and in plastics, paints, fertilizers, insecticides, soaps, and synthetic rubber. The uses of petroleum as a source of raw material in manufacturing are central to the functioning of modern industry. As petroleum resources are depleted, industry will rely more and more on heavy oil to satisfy the need for fuels, chemicals**.**
Many types of heavy oil exist, and a variety of production processes are being used and developed to recover it. However, technologies and services used for conventional oil face limitations with heavy oil.
Heavy oil typically has relatively low proportions of volatile compounds with low molecular weights and quite high proportions of high molecular weight compounds. The high-molecular-weight fraction of heavy oils is composed of compounds (not necessarily paraffins or asphaltenes) with high melting points and high pour points that greatly contribute to the fluid properties of heavy oil and hence to reduced mobility compared to conventional petroleum. It is typically this poor mobility of the crude oil, as opposed to accumulations of paraffins or asphaltenes in formation rock pore throats or production lines, that is usually the cause of production problems.
Some, but not all, heavy oils do contain moderate-to-high levels of asphaltene constituents. However, the asphaltene constituents do not become a problem unless they drop out of solution (precipitate) and build up in the formation or production string.
In summary, the heaviness of heavy oil is primarily the result of an internal balance between a relatively high proportion of complex, high-molecular-weight, non-paraffinic compounds and a low proportion of volatile, lower-molecular-weight compounds. The problems of producing heavy oil from the reservoir are typically a result of disturbing the internal balance, which, in turn, influences the mobility of the oil and the deposition of asphaltene constituents. Success with heavy oil depends as much on understanding the

fluid properties of the reservoir as it does on knowing the geology of the reservoir itself. The reason is that the chemical differences between heavy oil and conventional oil ultimately affect their viscosity.

Thermal recovery options in some reservoirs include the use of cyclical steam (huff 'n' puff), downhole heaters, or a relatively new commercial process called steam-assisted gravity drainage (SAGD). Other techniques, such as injecting slugs of water alternating with gas (WAG) are less efficient than thermal recovery but also less expensive. The use of steam influences the mobility of the oil, which influences recovery rates, but the enhanced oil recovery and artificial lift methods needed to produce changes to the already complex fluid characteristics of heavy oil.

2.1.5.1 Physical Properties

Heavy oil exhibits a wide range of physical properties, and several relationships can be made between various physical properties. Although the properties such as viscosity, density, and boiling range may vary widely, the ultimate or elemental analysis varies over a narrow range for a large number of samples. The carbon content is relatively constant, whereas the hydrogen and heteroatom contents are responsible for the major differences between heavy oils.

Initial inspection of the oil (conventional examination of the physical properties) is necessary. From this, it is possible to make deductions about the propensity for easy or difficult recovery. In fact, evaluation of heavy oil from physical property data to determine which recovery sequences should be employed for a particular crude oil is a predominant part of the initial examination of any heavy oil. Proper interpretation of the data resulting from the inspection of crude oil requires an understanding of their significance.

The chemical composition of heavy oil, however, is a much truer indicator of behavior than its physical properties. Whether the composition is represented in terms of compound types or (more likely) in terms of generic compound classes, it can assist in determining the nature of any potential interactions of the oil with the rock, for example, or with changes in pressure and temperature. Hence, chemical composition can play a large part in determining the nature of the products that arise from the recovery operations. It can also play a role in determining the means by which a particular feedstock should be processed. This becomes particularly important when partial upgrading in the reservoir is considered as a serious option for recovery.

Elemental (Ultimate) Analysis The analysis of heavy oil for the percentages of carbon, hydrogen, nitrogen, oxygen, and sulfur is perhaps the first method used to examine and evaluate the general nature of a feedstock. The atomic ratios of the various elements to carbon (i.e., H/C, N/C, O/C, and S/C) are frequently used for indications of the overall character of the heavy oil. It is also of value to determine the amounts of trace elements, such as vanadium and nickel, in a feedstock since these materials can have serious deleterious effects on catalyst performance during partial upgrading during recovery or even when using a partial upgrading process at the surface before transportation.

Of the data that are available, the proportions of the elements in heavy oil vary only slightly over narrow limits. Perhaps the more pertinent property in the present context is the sulfur content; sulfur content and API gravity represent the two properties that have the greatest influence on the value of heavy oil. The sulfur content varies from about 0.1% to about 5% by weight.

Metals Content

Metals (particularly vanadium and nickel) are found in most crude oils. Heavy oil contains relatively high proportions of metals, either in the form of salts or as organometallic constituents (such as the metalloporphyrin's), which are extremely difficult to remove from the feedstock. The metallic constituents may actually volatilize under thermal recovery operations and appear in the reservoir or in the production lines. Determination of metals in whole feeds can be accomplished by combustion of the sample so that only inorganic ash remains. The ash can then be digested with an acid and the solution examined for metal species by atomic absorption (AA) spectroscopy or by inductively coupled argon plasma (ICAP) spectrometry.

Density and Specific Gravity

Density is the mass of a unit volume of material at a specified temperature; it has the dimensions of grams per cubic centimeter (a close approximation to grams per milliliter). Specific gravity is the ratio of the mass of a volume of the substance to the mass of the same volume of water and is dependent on two temperatures, those at which the masses of the sample and the water are measured. When the water temperature is 4°C (39°F), the specific gravity is equal to the density in the centimeter-gram-second (CGS) system since the volume of 1 gallon of water at that temperature is, by definition, 1 ml. Thus, the density of water, for example, varies with temperature, and its specific gravity at equal temperatures is always unity. The standard temperatures for a specific gravity in the petroleum industry in North America are 60/60°F (15.6/15.6°C).

Specific gravity is influenced by chemical composition, but quantitative correlation is difficult to establish. Nevertheless, it is generally recognized that increased amounts of aromatic compounds result in an increase in density, whereas an increase in saturated compounds results in a decrease in density. It is also possible to recognize certain preferred trends between the API gravity of crude oils and residua and one or more of the other physical parameters. For example, a correlation exists between the API gravity and sulfur content, Conradson carbon residue, and viscosity. However, the derived relationships between the density of heavy oil and its fractional composition are valid only when applied to a certain type of heavy oil and may lose their significance when applied to heavy oil from different sources.

The values for density (and specific gravity) cover an extremely narrow range, considering the differences in heavy oil behavior. In an attempt to delineate a more meaningful relationship between the physical properties and processability of the various crude oils, the American Petroleum Institute devised a measurement of gravity based upon the Baumé scale for industrial liquids. The Baumé scale for liquids lighter than water was used initially:

Baumé = 140/sp gr @ 60/60°F – 130

However, a considerable number of hydrometers calibrated according to the Baumé scale were found at an early period to be in error by a consistent amount, and this led to the adoption of the equation

API = 141.5/sp gr @ 60/60°F – 131.5

The specific gravity of conventional crude oil usually ranges from about 0.8 (45.3°API) for conventional crude oil to about 1.0 (10°API) for heavy oil. This is in keeping with the general trend that a lower atomic hydrogen/carbon ratio (increased aromaticity) leads to a decrease in API gravity (or, more correctly, an increase in specific gravity).

Density, specific gravity, or API gravity may be measured, depending upon the properties of the heavy oil sample, by means of a hydrometer (ASTM D287, ASTM D1298) or by means of a pycnometer (ASTMD941, ASTM D1217). The variation of density with temperature, effectively the coefficient of expansion, is a property of great technical importance since most crude oils are sold by volume, and specific gravity is usually determined at the prevailing temperature (21°C, 70°F) rather than at the standard temperature (60°F, 15.6°C). The tables of gravity corrections (ASTM D1555) are based on an assumption that the coefficient of expansion is a function (at fixed temperatures) of density only.

Viscosity

The viscosity of heavy oils is a critical property in predicting oil recovery. In fact, viscosity is often cited as the single most important fluid characteristic governing the motion of crude oil. It is actually a measure of the internal resistance to motion of a fluid by reason of the forces of cohesion between molecules or molecular groupings. It is unfortunate that oil-rock interactions and reservoir structure are often omitted when the focus is on oil viscosity.

Many types of instruments have been proposed for the determination of viscosity, but as in the determination of density, the choice of an instrument depends upon the properties of the oil.

Finally, heavy oil is high viscosity oil and does not flow easily—the term is a relative term compared to conventional (light) heavy oil and relates to specific technical issues of production, transportation, and refining. Properties that distinguish heavy oil from conventional (light) heavy oil must (at least) be parameters such as higher viscosity, higher specific gravity, method of production, as well as the presence of higher amount of high molecular weight and polar constituents. Extra heavy oil has a much higher viscosity and lower API gravity than heavy oil, but while tar sand bitumen is immobile in the deposit, extra heavy oil is mobile in the reservoir.

2.1.5.2 Thermal Properties

The thermal properties of heavy oil offer insights into its characteristics, and by measuring such properties, a set of basic characteristics can be obtained that can be correlated with behavior during thermal methods of recovery. For the purposes of this section, the tests that produce data relating to the various thermal properties of heavy oil, as they influence recovery, are described. These properties provide advance information relating to the movement of the heavy oil in the reservoir and up the wellbore.

Carbon Residue

The carbon residue of heavy oil is a property that can be correlated with several other properties of the oil and may be used to evaluate the carbonaceous depositing characteristics of heavy oil during thermal recovery.

There are two older well-used methods for determining the carbon residue the Conradson method (ASTM D189) and the Ramsbottom method (ASTM D524). Both are equally applicable to heavy oil but the metallic constituents will give erroneously high carbon residues. The metallic constituents must first be removed from the oil or they can be estimated as ash by complete burning of the coke after carbon residue determination. There is no exact correlation between the two methods but it is possible to interconnect the data.

Another method (ASTM D4530) requires smaller sample amounts and was originally developed as a thermogravimetric method. The carbon residue produced by this method is often referred to as themicrocarbon residue. Agreements between the data from the three methods are good, making it possible to interrelate all of the data from carbon residue tests.

Specific Heat

Specific heat is the quantity of heat required to raise a unit mass of material through one degree of temperature (ASTM D2766). It is an extremely important engineering quantity in practice and is used in all calculations on heating and cooling heavy oil. Many measurements have been made on various hydrocarbon materials, but the data for most purposes may be summarized by the general equation:

$C= 1/d (0.388 + 0.00045t)$

where Cis the specific heat at t °F of an oil whose specific gravity 60/60°F is d. Thus, specific heat increases with temperature and decreases with specific gravity.

Heat of Combustion

The gross heat of combustion of heavy oil is given with a reasonable degree of accuracy by the equation

$Q= 12,400 – 2100d2$

where d is the 60/60°F specific gravity. Deviation is generally less than 1%, although highly aromatic heavy oil may show considerably higher values.

For thermodynamic calculation of equilibria, combustion data of extreme accuracy are required because the heats of formation of water and carbon dioxide are large in comparison with those of the hydrocarbons. Great accuracy is also required of the specific heat data for the calculation of free energy or entropy. Much care must be exercised in selecting values from the literature for these purposes since many of those available were determined before the development of modern calorimetric techniques.

Volatility

The volatility of a liquid or liquefied gas may be defined as its tendency to vaporize, that is, to change from the liquid to the vapor or gaseous state. Because one of the three essentials for combustion in a flame is that the fuel be in the gaseous state, volatility is a primary characteristic of liquid fuels. The distillation profile is also a measure of the relative amounts of these liquid fuels (albeit small and unrefined) in heavy oil.

Similarly, there must be some estimate of the ability of the constituents of heavy oil to distill, or steam distill, from the oil during thermal methods of enhanced oil recovery. However, before any volatility tests are carried out, it must be recognized that the presence of more than 0.5% water in test samples of heavy oil can cause several problems during distillation procedures. Water has a high heat of vaporization, necessitating the application of additional thermal energy to the distillation flask. Water is relatively easily superheated, and therefore excessive bumping can occur, leading to erroneous readings and the real potential for destruction of the glass equipment.

In addition, steam formed during distillation can act as a carrier gas, and high-boiling-point components may end up in the distillate (often referred to as steam distillation).

Centrifugation can be used to remove water (and sediment) if the sample is not a tight emulsion. Other methods that are used to remove water include:

1. Heating in a pressure vessel to control loss of light ends
2. Addition of calcium chloride as recommended in ASTM D1160

3. Addition of an azeotroping agent such as iso-propanol or n-butanol
4. Removal of water in a preliminary low-efficiency or flash distillation followed by re blending of the hydrocarbon which co-distills with the water into the sample (see also IP 74)
5. Separation of the water from the hydrocarbon distillate by freezing

For some purposes, it is necessary to have information on the initial stage of vaporization and the potential hazards, even with heavy oil, that such a property can cause. To supply this need, flash-and-fire, vapor pressure, and evaporation methods are available. The data from the early stages of the several distillation methods are also useful. For other uses, it is important to know the tendency of a product to partially vaporize or to completely vaporize, and in some cases, to know if small quantities of high-boiling components are present. For such purposes, chief reliance is placed on the distillation methods.

The flash point of petroleum or a petroleum product is the temperature to which the product must be heated under specified conditions to give off sufficient vapor to form a mixture with air that can be ignited momentarily by a specified flame.

The flash point of heavy oil can also be used to detect contamination. A substantially lower flash point than expected for a product is a reliable indicator that a product has become contaminated with a more volatile product, such as gasoline. The flash point is also an aid in establishing the identity of a particular hydrocarbon contaminant.

A further aspect of volatility that receives considerable attention is the vapor pressure of heavy oil, which may be close to zero. The vapor pressure is the force exerted on the walls of a closed container by the vaporized portion of a liquid. Conversely, it is the force that must be exerted on the liquid to prevent it from vaporizing further. The vapor pressure increases with temperature. The temperature at which the vapor pressure of a liquid, either a pure compound or a mixture of many compounds, equals one atmosphere pressure (14.7 psi, absolute) is designated as the boiling point of the liquid.

Liquefaction and Solidification

The liquefaction and solidification of heavy oil seems to draw little attention in the standard petroleum science textbooks. Yet these properties are very important in the handling of heavy oil, both at the wellhead and in the refinery. In fact, since heavy oil can be a borderline liquid or near solid at ambient temperature, problems may arise from solidification during normal use or storage. Recently, more emphasis has been placed on the pour point, which, in conjunction with the reservoir temperature, can give indications of the fluidity and mobility of the heavy oil in the reservoir. The pour point of a crude oil was originally applied to crude oil that had a high wax content. More recently, the pour point, like the viscosity, is determined principally for use in pumping arid pipeline design calculations**.**

2.1.6 Why Heavy Oil is Needed?

The gradual depletion of the world's lighter petroleum resources and the increasing prices for these commodities means a rising need to process alternative heavier feedstock. These alternatives include extra heavy oil, bitumen from oil sands, and residues from light and moderate crude oil refining. Upgrading oil sands and heavy oil is an essential part as it adds tremendous value to the raw resource and allows it to be further processed into fuels and lubricants at existing refineries, and used as feedstock in petrochemical plants. Petroleum upgrading represents a suite of physical and chemical processes whereby raw extra heavy oil and bitumen extracted from oil sands are transformed into synthetic crude oil to providing a safe and secure energy source to fill the widening gap between our future energy supply and demand requirements. Forecasts predict that a continuous expansion in world energy consumption must extend at least until 2035, as indicated by the U.S. Energy Information Administration (See Figure 2.2). For this reason, heavy oil reserves essential to supply the global energy.

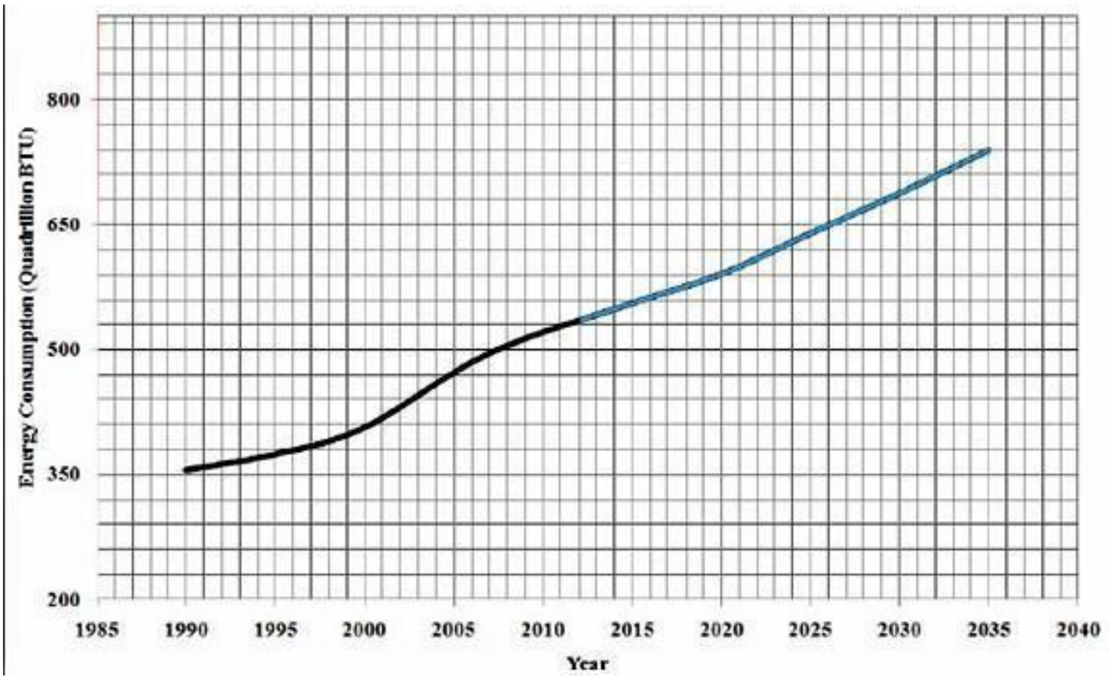

Fig 2.2 World market energy consumption – Forecast up 2035. Adapted from DOE/EIA 2010 International Energy Outlook, U.S. Energy Information Administration

2.2 Methods for Oil Recovery

The initial production of crude oil from an underground reservoir is achieved by the use of the natural energy of the reservoir. As soon as the reservoir is opened, the natural energy comes into play and, whether through gas pressure or water pressure, forces the fluids to the surface facility (primary production). In the process, the actual sources of natural reservoir energy that lead to primary production include the swelling of reservoir fluids, the release of solution gas as the reservoir pressure declines, nearby communicating aquifers, and gravity.

When the natural reservoir energy has been depleted through production, it becomes necessary to supplement or even substitute the natural reservoir energy with energy from an external source. This is usually accomplished by the injection of fluids, such as natural gas or water (secondary recovery). The main purpose of either a natural gas injection process (gas flooding) or a water injection process (water flooding) is to depressurized the reservoir and then to maintain the reservoir at a high pressure. The term pressure maintenance is sometimes used to describe a secondary recovery process.

When gas is used as the pressure maintenance agent, it is usually injected into a zone of free gas (i.e., a gas cap) to maximize recovery by gravity drainage. The injected gas is usually natural gas produced from the reservoir in question which defers the sale of that gas until the gas flooding operation is completed and the gas can be recovered. On the

other hand, other gases, such as nitrogen, can be injected to maintain reservoir pressure, which allows the natural gas to be sold as it is produced.
The situation is different for heavy oil and tar sand bitumen where the reservoirs of deposits have little to no reservoir energy in the form of the pressure exerted within the reservoir by the presence of or water. Heavy oil reservoir and tar sand deposits are found in the microscopic pores of sedimentary rocks such as sandstone and limestone. Not all of the pores in a reservoir rock or deposit will contain heavy oil or bitumen—some will be filled with water or brine—the latter is water that is saturated with minerals. Seismic surveys are used to try to predict where fields may be found but the only way of making certain is by drilling.
Production rates from reservoirs depend on a number of factors, such as reservoir geometry (primarily formation thickness and reservoir continuity), reservoir pressure, reservoir depth, rock type and permeability, fluid saturations and properties, extent of fracturing, number of wells and their locations, and the ratio of the permeability of the formation to the viscosity of the heavy oil or bitumen and what it will take to modify the viscosity to enable recovery methods to be effective. Operators can increase production over that which would naturally occur by such methods as fracturing the reservoir to open new channels for flow, injecting gas and water to increase the reservoir pressure, or lowering oil viscosity with heat or chemicals. These supplementary techniques are expensive, and the extent to which they are used depends on such external factors as the operator's economic condition, sales prospects, and perceptions of future prices.
The extraordinary geological variability of different reservoirs means that production profiles differ from field to field. Heavy oil reservoirs can be developed to significant levels of production and maintained for a period of time by supplementing natural drive force, while gas reservoirs normally decline more rapidly.

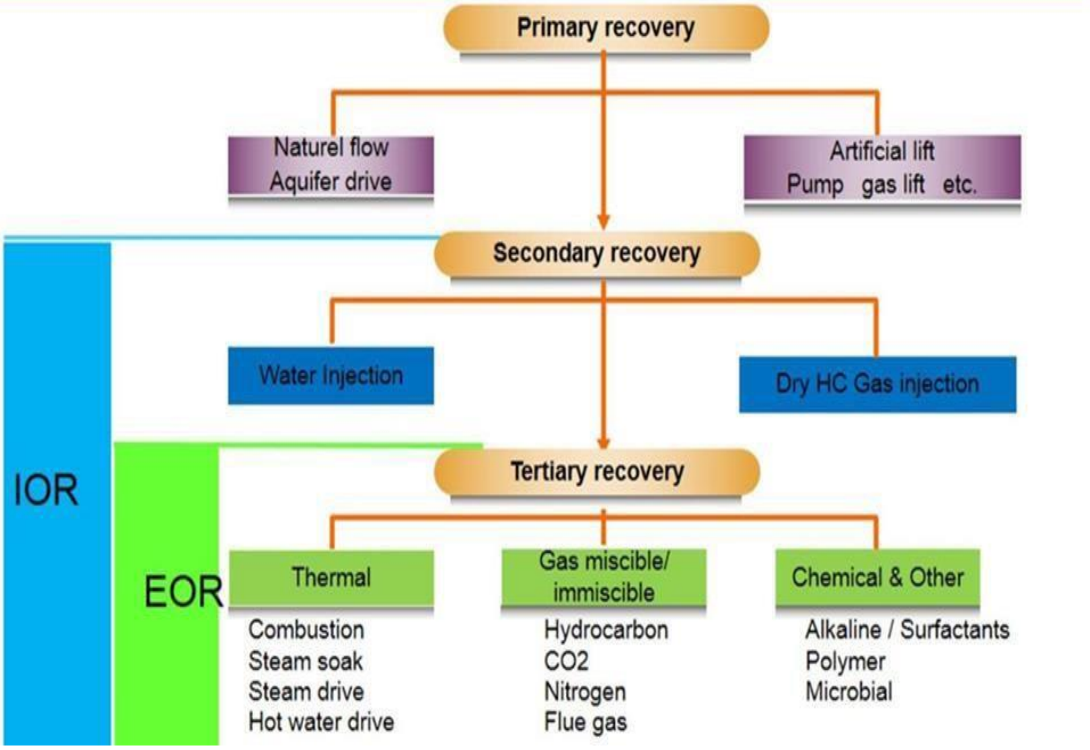

Fig 2.3: General Methods for Oil Recovery

2.2.1 Primary Recovery Methods

The initial stage in producing oil from a reservoir (primary recovery, primary production) is the stage in which oil is forced to the surface by such natural forces as: (1) expansion of oil; (2) expansion of the contained gas; (3) displacement by migration of naturally pressurized water from a communicating zone such as in natural water drive; and (4) drainage downward from a high elevation in a reservoir to wells penetrating lower elevations. The natural expulsive forces present in a given reservoir depend on rock and fluid properties, geologic structure and geometry of the reservoir, as well as on the rate of oil and gas production several of the forces may be present in a given reservoir. Recovery efficiency of conventional (light) crude oil varies in the primary stage from 10% to approximately 50% v/v of the oil in place. However, these numbers do not apply to heavy oil or to tar sand bitumen which are generally immune to recovery by primary methods.
Primary recovery occurs as wells produce because of natural energy from expansion of gas and water within the producing formation, which pushes fluids into the well bore and lifts them to the surface.

2.2.2. Secondary Recovery Methods

Secondary recovery processes are necessary because most of the crude oil in a reservoir remains in place after the natural energy pressurizing the reservoir has been dissipated. Several techniques are available for repressuring the reservoir by injecting fluids into the reservoir to augment the natural forces have been widely used for many years. Fluids, most commonly water (water flooding) and (although not truly a fluid but considered to

be a reservoir fluid) natural gas (gas flooding) are injected into the reservoir through a series of wells (injection wells) to force the crude oil toward another series of wells (production wells). The pattern of injection and production wells most appropriate to a reservoir are a technical matter and depend upon the properties of the reservoir and the properties of the crude oil. Furthermore, it is frequently desirable to initiate such processes as soon as sufficient knowledge is available of the geology of the reservoir and the type of natural expulsive forces that are operative.
And there is no reason (in fact, it is often disadvantageous) to delay the fluid injection process until the natural energy in a reservoir is exhausted.
Most often, secondary recovery is accomplished by injecting gas or water into the reservoir to replace produced fluids and thus maintain or increase the reservoir pressure. When gas alone is injected, it is usually put into the top of the reservoir, where petroleum gases normally collect to form a gas cap. Gas injection can be a very effective recovery method in reservoirs where the oil is able to flow freely to the bottom by gravity. When this gravity segregation does not occur, however, other means must be sought.
Secondary recovery occurs as artificial energy is applied to inject fluids into the well bore and lift fluids to the surface. This may be accomplished by injecting gas down a hole, installing a subsurface pump, or injecting gas or water into the formation itself. Secondary recovery is done when well, reservoir, facility, and economic conditions permit.

2.2.3 Enhanced Oil Recovery Methods

Enhanced oil recovery is one of the technologies needed to maintain reserves at an acceptable level. EOR methods used to improve reservoir recovery efficiency. Several enhanced oil recovery (EOR) techniques generally grouped together as tertiary production.

Describes the intent of EOR methods as follows:

1. To improve sweep efficiency by reducing the mobility ratio between injected and in-place fluids.
2. To eliminate or reduce capillary and interfacial forces and thus improve displacement efficiency.
3. To act on both phenomena simultaneously.

A decision must be made whether a tertiary recovery method may be used. The latter depends on reservoir complexity and reservoir conditions, field exploitation strategy is greatly affected by economics.
Improved Oil Recovery (IOR) methods encompass Enhanced Oil Recovery (EOR) methods as well as new drilling and well technologies, intelligent reservoir management and control, advanced reservoir monitoring techniques and the application of different enhancements of primary and secondary recovery processes In the past, chemical, thermal, and miscible techniques have been used by the industry on a commercial scale. EOR techniques require the injection of chemical compounds dissolved in water, the injection of steam, or the injection of a gas that is miscible with the oil in place. The amount of oil that can ultimately be recovered by existing EOR techniques is directly related to the price of crude oil. Important analysis before EOR projects begin: All EOR projects begin with an analysis of the nature, location, and causes of residual oil saturations (Sr) that remain after primary and/or secondary recovery operations.

Tertiary recovery includes all other methods used to increase the amount of oil recovered. The Efficiency of an Enhanced Recovery Method is a measure of its ability to provide greater. The optimal application of each type depends on reservoir temperature, pressure, depth, net pay, permeability remaining oil and water saturation, porosity and fluid properties such as oil API gravity and viscosity hydrocarbon recovery than by natural depletion, at an economically attractive production rate. These processes are summarized in the following:

1. Thermal methods: steam stimulation, steam flooding, hot water drive, and in-situ combustion
2. Chemical methods: Alkaline-surfactant-polymer processes (ASP), caustic and micellar/polymer flooding.
3. Miscible enhanced oil recovery OIEOR) methods including: hydrocarbon gas**,** **C02,** nitrogen, flue gas.
4. Microbial.

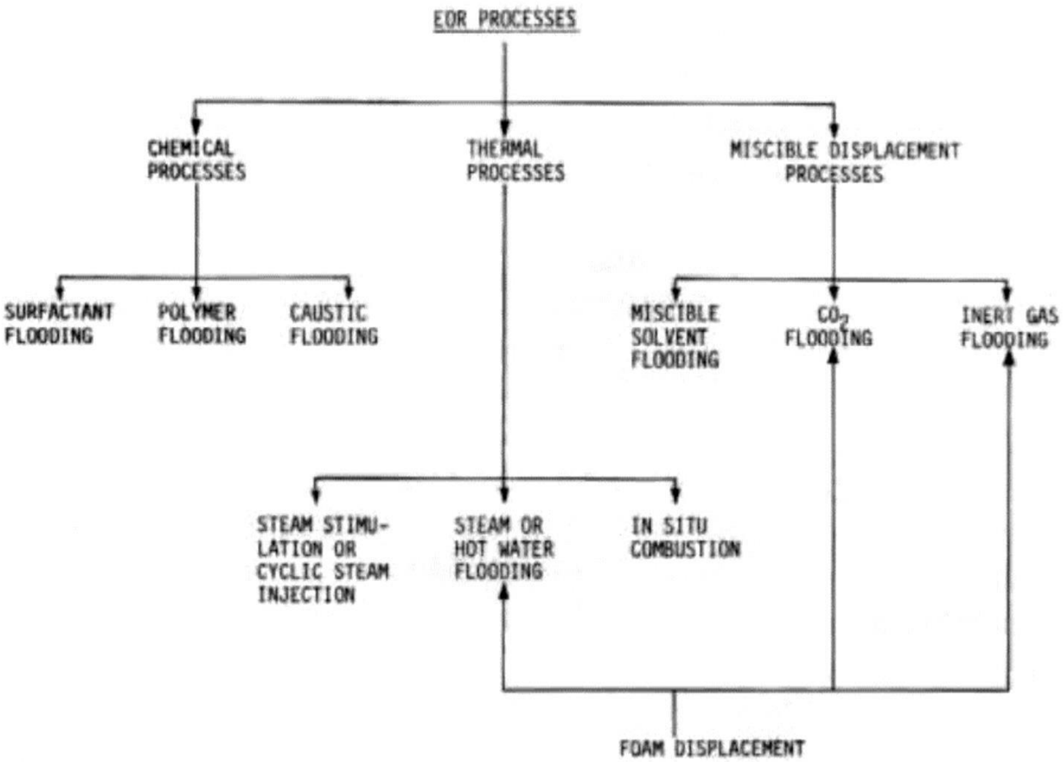

Fig 2.4: EOR process

2.2.3.1 Thermal Methods

Thermal methods raise the temperature of regions of the reservoir to heat the crude oil nd/or vaporize part of the oil and thereby decrease the mobility ratio. Thermal methods include the injection of hot water, steam or other gas, or by conducting combustion in the formation and reduce its viscosity ain situ of oil or gas.

The increase in heat reduces the surface tension and increases the permeability of the oil and improves the reservoir seepage conditions. The heated oil may also vaporise and then condense forming improved oil.

This approach however, requires substantial investment in special equipment. Both thermal recovery methods also severely damage the underground well structure, as well as pose safety risks in the larger production process. For these reasons, the methods are not generally used very often.

Primary production processes and secondary production processes from reservoirs containing heavy, low-gravity, viscous crude oils is usually a small fraction of the initial oil in place. This is due to the fact that these types of oils are very thick and viscous and as a result do not migrate readily to producing wells. However, the typical relationship between the viscosity of a heavy, viscous crude oil and temperature shows that viscosity decreases by orders of magnitude with an increase in temperature of 38°C to 95°C (100°F to 200°F) which, in the case of a heavy oil reservoir, will reduce the oil viscosity significantly and will flow much more easily to a producing well. The temperature of a reservoir can be raised by injecting a hot fluid (such as hot water or steam) or by generating thermal energy in situ by combusting the oil.

Viscosity, a measure of a liquid's ability to flow, varies widely among crude oils—some crudes flow easily (water-like) while others have more difficulty in flow properties. However, the viscosity of most crude oils dramatically decreases as temperature increases, and the purpose of all thermal oil recovery processes is to apply heat to the oil to enable flow under the impetus of injected fluids, which may be steam or hot water (steam injection), or air (combustion processes). Thus, thermal processes for oil recovery have found most use when the oil in the reservoir has a high viscosity.

Thermal EOR processes add heat to the reservoir to reduce oil viscosity and/or to vaporize the oil. In both instances, the oil is made more mobile so that it can be more effectively driven to producing wells. In addition to adding heat, these processes provide a driving force (pressure) to move oil to producing wells. The two main types of thermal recovery are:

2.2.3.1.1 Steam flooding

Steam flooding methods include: 1 steam drive - 2- cyclic steam injection.

Steam flooding introduces heat to the reservoir by pumping steam into the well in a pattern similar to that of water injection. Eventually the steam condenses to hot water. In the steam zone the oil evaporates and in the hot water zone the oil expands. As a result, the oil expands, the viscosity drops and the permeability increases. To ensure success, the process has to be cyclical. This is the principal enhanced oil recovery program in use today.

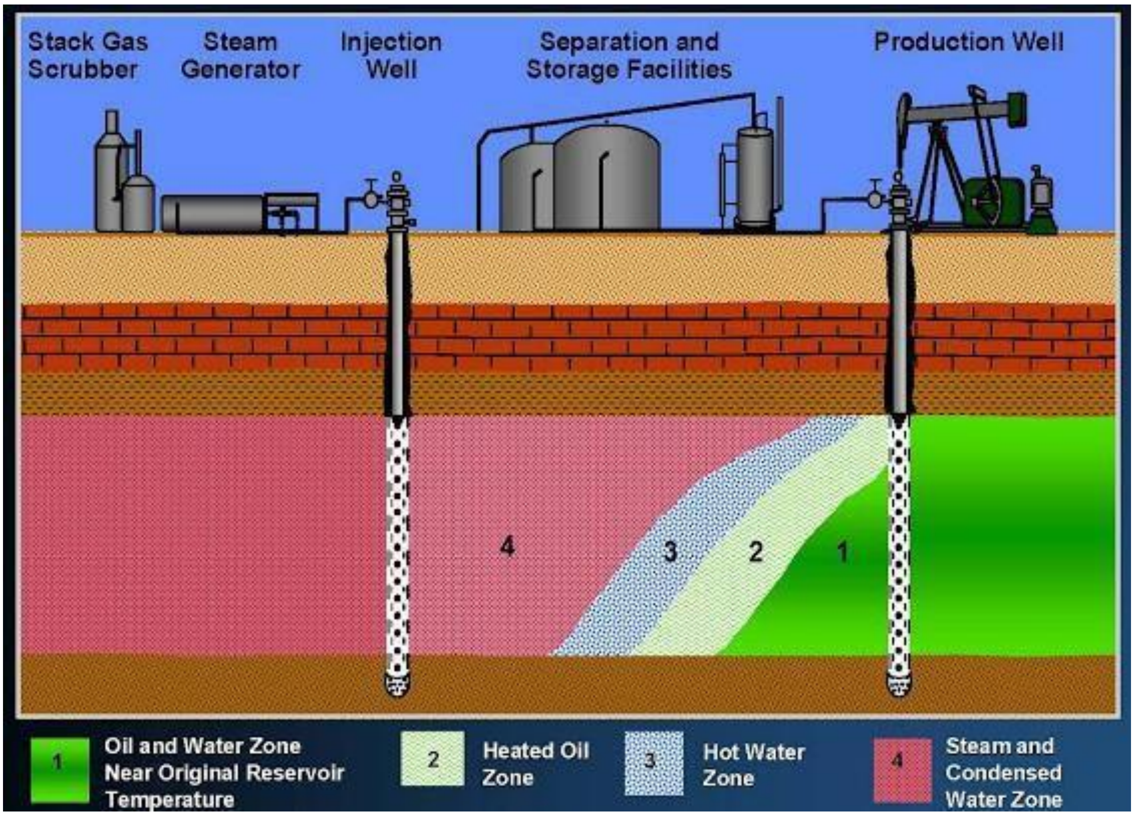

Fig 2.5: Steam flooding

2.2.3.1.2 Steam drive

The steam drive process (or processes) are considerably different in performance from hot-water drives due to the presence and effects of the steam which causes low molecular weight constituents in the oil to be distilled and carried along as hydrocarbon constituents in the gas phase. When and wherever the steam condenses, the condensable hydrocarbon components also condense and reduce the viscosity of the crude oil at the condensation front. Moreover, the condensing steam makes the displacement process more efficient and improves the sweep efficiency. Thus, the net effect is that recovery from steam drives is significantly higher than from hot water drives.
An important additional phenomenon affecting displacement in steam drives is the steam distillation of the relatively low-boiling fractions in the oil. Distillation causes the vapor phase to be composed not only of steam but also of condensable hydrocarbon vapors. Some hydrocarbon vapors will condense along with the steam, mixing with the original crude and increasing the amount of relatively light fractions in the residual oil trapped by the advancing condensate water ahead of the front. Dilution by the low-boiling constituents causes some of the trapped oil to be displaced by the condensed water. The remainder of the oil is stripped by the steam of all the remaining low boilers to leave the higher boiling residuum.The lower-boiling constituents help to regenerate and maintain a solvent bank just downstream of the condensation front. During the process, the composition of the produced oil generally does not change until the steam zone is relatively near, at which point the volatile content increased markedly.

Steam drive injection (steam injection) has been commercially applied since the early 1960s. The process occurs in two steps: (1) steam stimulation of production wells, that is, direct steam stimulation; and (2) steam drive by steam injection to increase production from other wells (indirect steam stimulation). Steam drive differs considerably in performance from hot-water drive—the difference in performance is due to the presence and effects of the condensing vapor. The presence of the gas phase causes low-boiling constituents present in the crude oil to be distilled and carried along as hydrocarbon components in the gas phase. When the steam condenses, the condensable hydrocarbon constituents of the vapor also condense and reduce the viscosity of the crude oil at the condensation front. In addition, the condensing steam makes the displacement process more efficient and improves the sweep efficiency and the net effect of the steam drive is that crude oil recovery is significantly higher than the crude oil recovery from hot-water drives. (**Fig. 2-6**)

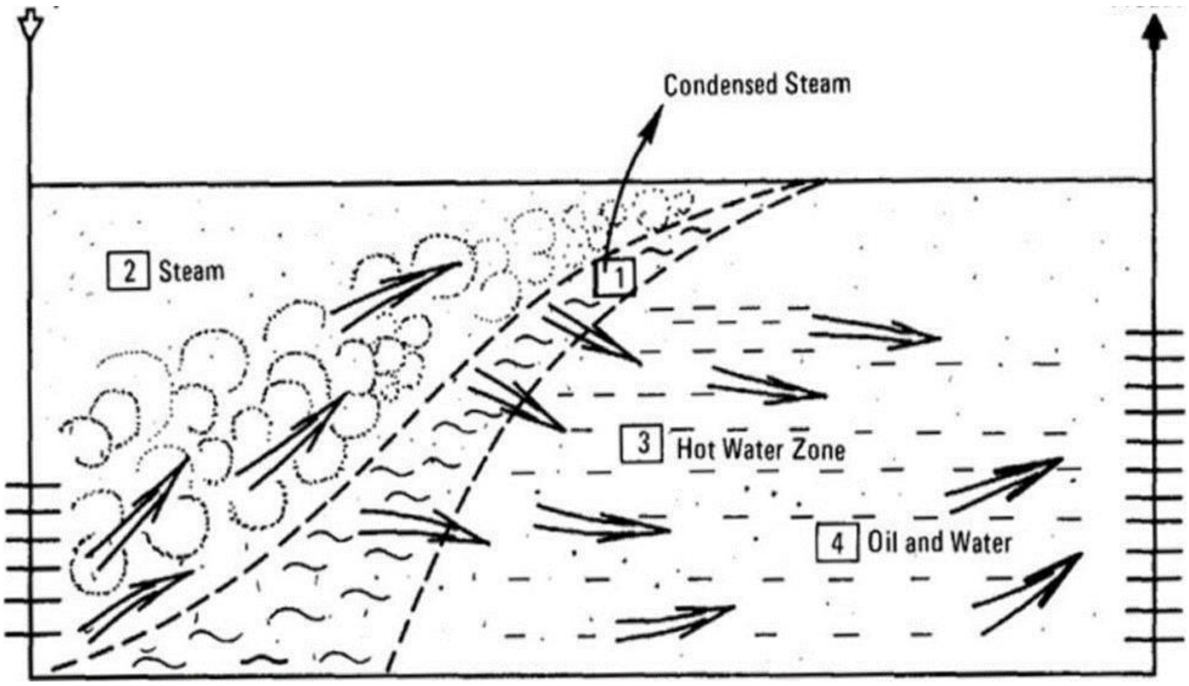

Fig 2.6: Steam Drive Process Scheme and Zones Formed in The Reservoir.

When there is some natural reservoir energy, steam stimulation normally precedes steam drive. In steam stimulation, heat is applied to the reservoir by the injection of high-quality steam into the produce well. This cyclic process, also called huff and puff or steam soak, uses the same well for both injection and production. The period of steam injection is followed by production of reduced viscosity oil and condensed steam (water). One mechanism that aids production of the oil is the flashing of hot water (originally condensed from steam injected under high pressure) back to steam as pressure is lowered when a well is put back on production.

2.2.3.1.3 cyclic steam stimulation

Cyclic steam injection is the alternating injection of steam and production of oil with condensed steam from the same well or wells. Thus, steam generated at surface is injected in a well and the same well is subsequently put back on production. A cyclic steam injection process includes three stages. The first stage is injection, during which a measured amount of steam is introduced into the reservoir. The second stage (the soak period) requires that the well be shut in for a period of time (usually several days) to allow uniform heat distribution to reduce the viscosity of the oil (alternatively, to raise the reservoir temperature above the pour point of the oil). Finally, during the third stage, the now-mobile oil is produced through the same well. The cycle is repeated until the flow of oil diminishes to a point of no returns. (**Fig. 2-7**)

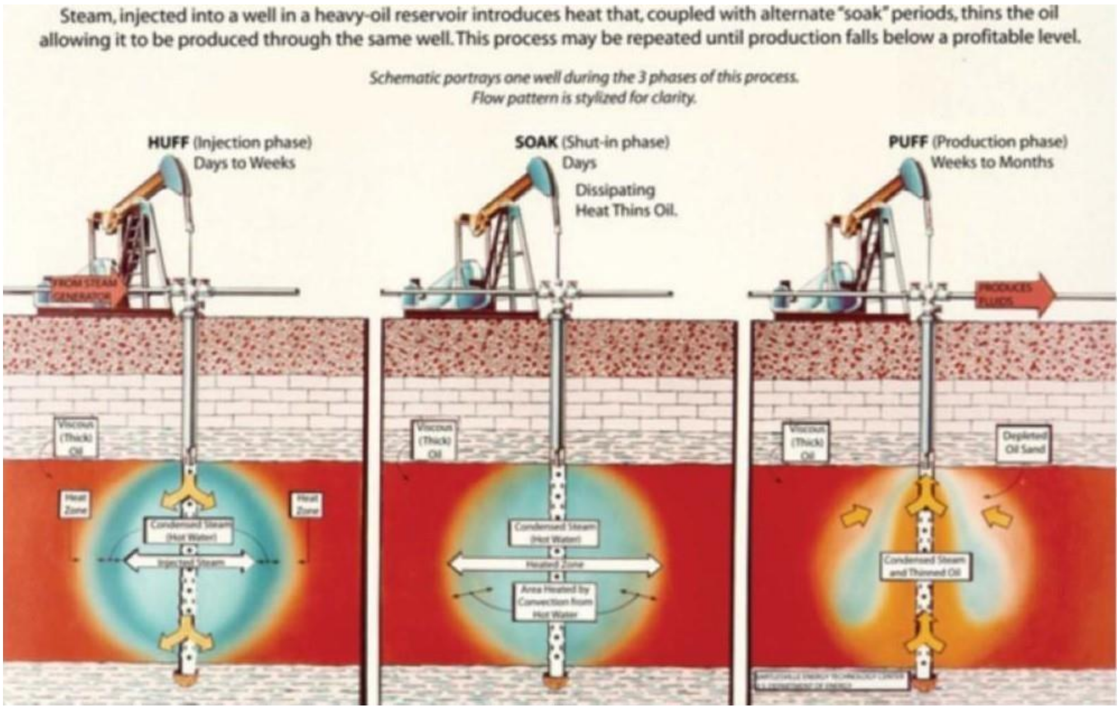

Fig 2.7: Cyclic steam process

2.2.3.1.4 Combustion to introduce heat to the reservoir

In-situ combustion (ISC) is an enhanced oil recovery method in which the air is injected into the reservoir burning the heaviest crude oil components generating heat and combustion gases that enhance recovery by reducing oil viscosity and pressurizing the system, respectively. In this process, highly exothermic reactions occur in the porous medium resulting in significant increases in the temperature. For heavy oils, a 300-400 °C increase in temperature is not uncommon. Large temperature differences signify heat transfer and also will result in the phase change. ISC involves many phenomena, making modeling complex. So, the engineering of the process is more difficult than any other method of crude oil recovery, but the advantages of in-situ combustion motivate researchers to investigate on it.

In situ combustion of oil on site or fire flood, works best when the oil saturation and porosity are high. Combustion generates the heat within the reservoir itself. Continuous injection of air, or other gas mixture with high oxygen content, will maintain the flame front. As the fire burns, it moves through the reservoir towards the production wells. Heat from the fire reduces oil viscosity and helps to vaporize reservoir water to steam. The steam, hot water, combustion gas and a bank of distilled solvent all act to drive oil in front of the fire toward production wells (Figure2.8).

The performance of in situ combustion is predominantly determined by the four following factors: (1) the quantity of oil that initially resides in the rock to be burned; (2) the quantity of air required to burn the portion of the oil that fuels the process; (3)

the distance to which vigorous combustion can be sustained against heat losses; and (4) the mobility of the air or combustion product gases.

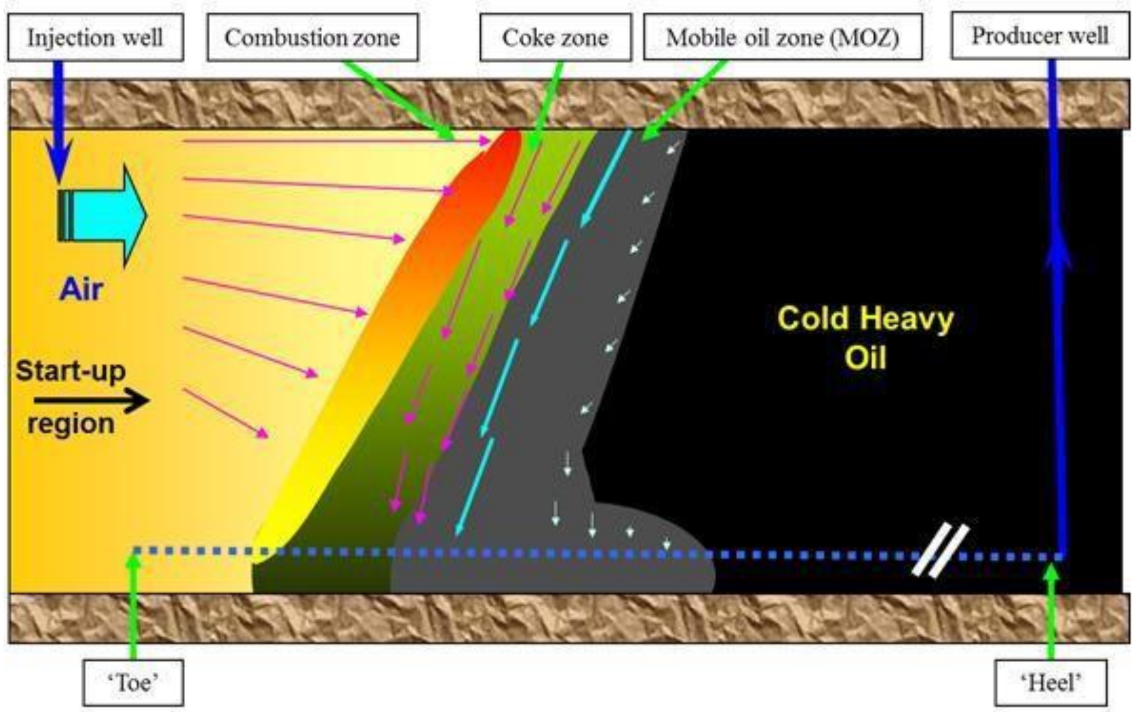

Fig 2.8: In-situ combustion process

There are three methods of combustion: Dry forward, reverse and wet combustion. The dry forward method uses an igniter to set fire to the oil. As the fire progresses, the oil is pushed away from the fire toward the producing well. In the reverse method, the air injection and the ignition occur from opposite directions. In the wet combustion method, water is injected just behind the front and turned into steam by the hot rock. This quenches the fire and spreads the heat more evenly.

2.2.3.1.5 Hot water injection:

In this method sand is produced aggressively along with the heavy oil without applying heat. The oil production is improved substantially through the regions of increased permeability wormholes. The basis of this process is the oil production and recovery when sand production occurs naturally. The production of the unconsolidated un-cemented reservoir sand results in significantly higher oil production. In order to make it cost effective, the choice of fluid can be made according to the availability of fluid and its production response of the crude oil. For example, seawater may be injected in the undersea reservoir, which can save the cost of delivery of water to the reservoir. Also the mineralogy of the reservoir should be considered; for example, steam or hot water should not be injected without first considering their effects on the reservoirs containing swelling clays.

2.2.3.2 Chemical Methods

Chemical flooding involves the addition of one or more chemical compounds to an injected fluid either to reduce the interfacial tension between the reservoir oil and the injected fluid or to improve the sweep efficiency of the injected fluid. There are three general methods in chemical flooding technology: (1) alkaline flooding; (2) polymer flooding; and (3) micellar-polymer flooding. Alkaline flooding and micellar-polymer flooding use chemicals that reduce the interfacial tension between an oil and a displacing fluid. Polymer flooding uses a macromolecule to increase the displacing fluid viscosity which leads to improved sweep efficiency in the reservoir.

Technical issues that have arisen with the use of chemical processes include: (1) screening chemicals to optimize the microscopic displacement efficiency; (2) making contact with the oil in the reservoir; and (3) maintaining good mobility in order to lessen the effects of viscous fingering. The requirements for screening of chemicals vary with the type of process and the chemicals must also be able to tolerate the environment in which they are used. Also, high temperature and salinity may limit the chemicals that could be used.

2.2.3.2.1 Alkaline Flooding

Alkaline flooding involves the use of aqueous solutions of certain chemicals, such as sodium hydroxide, sodium silicate, and sodium carbonate, that are strongly alkaline. These solutions will react with constituents present in some crude oils or present at the rock/crude oil interface to form detergent-like or surfactant-type materials which reduce the ability of the formation to retain the oil. These chemicals enhance oil recovery by one or more of the following mechanisms: interfacial tension reduction; spontaneous emulsification; or wettability alteration. These mechanisms rely on the in-situ formation of surfactants during the neutralization of petroleum acids in the crude oil by the alkaline chemicals in the displacing fluids. Alkaline substances that have been used include sodium hydroxide, sodium orthosilicate, sodium metasilicate, sodium carbonate, ammonia, and ammonium hydroxide. Sodium hydroxide has been the most popular.

When an alkaline solution is mixed with certain crude oils (high-acid crude oils are an example of such oils), surfactant molecules are formed formation of the surfactants in situ raised the possibility that the interfacial tension between the brine and oil phases could be reduced. The reduction of interfacial tension causes the microscopic displacement efficiency to increase, which thereby increases oil recovery. There are optimum concentrations of alkaline and salt and optimum pH where the interfacial tension values experience a minimum.

Several mechanisms have been identified that aid oil recovery in the alkaline process. These include the following: (1) lowering of the interfacial tension; (2) emulsification of the oil; and (3) wettability changes in the rock formation. All three mechanisms can affect the microscopic displacement efficiency, and emulsification can also affect the macroscopic displacement efficiency.

The addition of sodium hydroxide to injection water to aid recovery. It does this by lowering the surface tension, reversing the rock wettability, emulsifying the oil, mobilizing the oil and helping to draw the oil out of the rock.

In areas with relatively poor physical properties and low permeability, there will still be a lot of residual oil left behind underground after using artificial water drive (e.g. generally heterogeneous sandstone reservoir results in ultimate oil recovery of only about 30 per cent).

2.2.3.2.2 Polymer Flooding

Polymer flooding is being adopted at an earlier stage in waterfloods because of its capability to control breakthrough and increase areal sweep efficiency.

Polymer flooding is one of the most widely used EOR methods to retrieve oil left behind after conventional recovery processes. It’s an augmented water flooding technique

introduced in the 1960’s, mainly used for heterogeneous reservoirs, to retrieve oil after areas in the reservoir with high permeability have been highly water flooded.
The addition of polymers to an injected water can often increase the effectiveness of a conventional water flood. Polymers are usually added to the water in concentrations ranging from 250 to 2000 parts per million (ppm) and a polymer solution is typically more viscous than a brine without polymer. In a flooding application, the increased viscosity changes the mobility ratio between the injected fluid and the reservoir oil leading to better vertical and areal sweep efficiencies and thus higher oil recoveries. Polymers have also been used to alter gross permeability variations in some reservoirs. In this application, polymers form a gel-like material by cross-linking with other chemical species and the polymer gel deposits in large permeability streaks and fractures diverting the flow of any injected fluid to a different location. Polymer flooding has seen success in moderately heterogeneous reservoirs and reservoirs containing oils with low viscosity (<100 cP).
The polymer flood process is:

1-Injection of polymer slug 0.3 or higher PV. 2-Injection of a low-salinity brine(freshwater) "pad" to protect the slug from brine / formation water. 3-Injection of brine / formation water chase fluid and by continuous drive water injection.
As explained by CNPC: “Polymer flooding is a tertiary recovery method by adding high-molecular-weight polyacrylamide into injected water, so as to increase the viscosity of fluid, improve volumetric sweep efficiency, and thereby further increase the oil recovery factor.
In the process, a polymer-thickened water solution process is introduced after the chemicals are injected to help obtain a more uniform movement (sweep) through the reservoir. Fresh water is then injected behind the polymer solution to prevent contamination from the final drive water which may be salty or otherwise incompatible with the chemicals. Alkaline flooding is usually more efficient if the acid content of the reservoir oil is relatively high. A new modification to the process is the addition of surfactant and polymer to the alkali, giving rise to an alkaline-surfactant-polymer enhanced oil recovery method. Although emulsification in alkaline flooding processes decreases injection fluid mobility to a certain degree, emulsification alone may not provide adequate sweep efficiency. Sometimes polymer is included as an ancillary mobility control chemical in an alkaline water flood to augment any mobility ratio improvements due to alkaline-generated emulsions (**Fig. 2-9**).

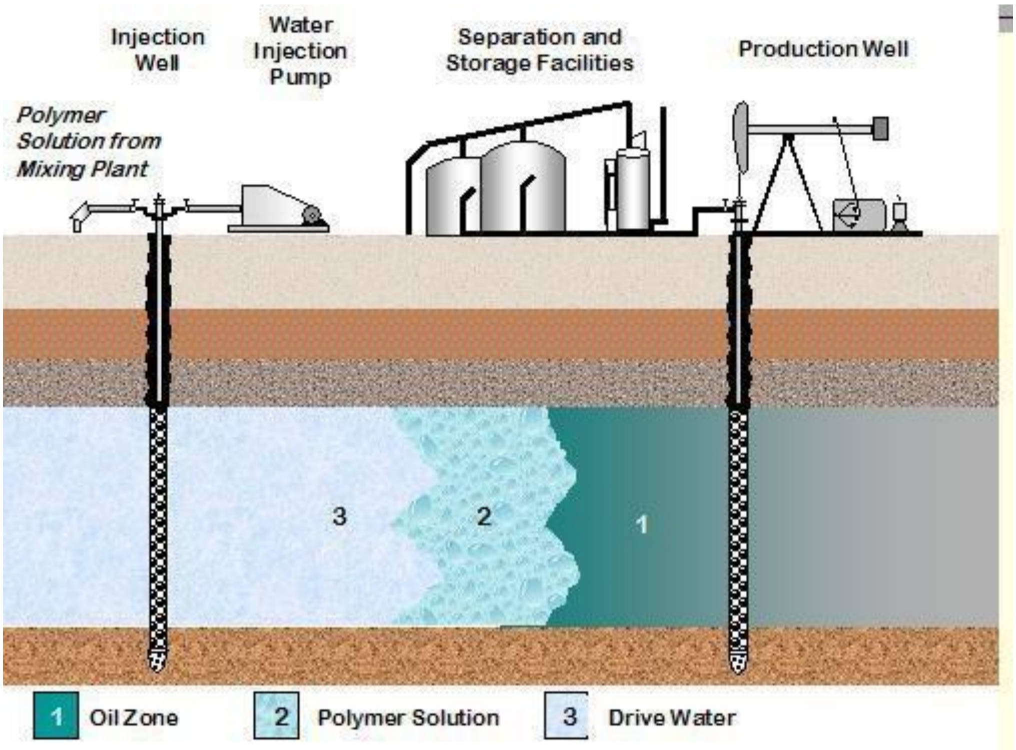

Fig 2.9: Chemical (Polymer Flooding)

Two general types of polymers have been used: (1) polyacrylamides; and (2) biologically produced polysaccharides. Polyacrylamides are long molecules with a small effective diameter and are susceptible to mechanical shear. High rates of flow through valves will sometimes break the polymer into smaller entities and reduce the viscosity of the solution, this can also occur as the polymer solution passes through the pore openings on the sand face of the injection well. However, polyacrylamides are also sensitive to salt (NaCl) and high concentrations of salt (in excess of 1% to 2% w/w) have an adverse effect on the viscosity-building effect of the polymers. On the other hand, polysaccharides are less susceptible to both mechanical shear and salt and, since they are produced biologically, care must be taken to prevent biological degradation in the reservoir. Typically, the use of polymers does not affect the microscopic displacement efficiency and the improvement in oil recovery is due to an improved sweep efficiency over what is obtained during a conventional water flood. Typical oil recoveries from polymer flooding applications are varied and are more likely to be successful if the process is initiated early in the producing life of the reservoir.

2.2.3.2.3 Micellar-Polymer Flooding

The micellar-polymer process uses a surfactant to lower the interfacial tension between the injected fluid and the reservoir oil. The surfactant migrates to the interface between the oil and water phases and helps make the two phases more miscible. Interfacial tensions can be reduced from approximately 30 dynes/cm, found in typical waterflooding applications, to 10−4 dynes/cm with the addition of as little as 0.1% to 5.0% w/w surfactant to water–oil systems.

As the interfacial tension between an oil phase and a water phase is reduced, the capacity of the aqueous phase to displace the trapped oil phase from the pores of the rock matrix

increases. The reduction of the interfacial tension results in a shifting of the relative permeability such that the oil will flow much more readily at lower oil saturations.
When surfactants are mixed above a critical saturation in a water-oil system, the result is a stable micellar solution which is made up of microemulsions that are homogeneous, transparent, and stable to phase separation. A microemulsion consists of external and internal phases sandwiched around one or more layers of surfactant molecules. The external phase can be either aqueous or hydrocarbon in nature, as can the internal phase. The microemulsions can exist in several shapes, which depend on the concentrations of surfactant, oil, water, and other constituents. Spherical microemulsions have a typical size ranging from 10^{-6} to 10^{-4}mm.
There are, in general, two types of micellar–polymer processes: (1) one which uses a low-concentration surfactant solution (<2.5% w/w) but a large injected volume (up to 50% pore volume); and (2) another which involves use of a high-concentration surfactant solution (5% to 12% w/w) and a small injected volume (5% to 15% v/v of the pore volume). Either type of process has the potential of achieving low interfacial tensions with a wide variety of brine–crude oil systems. Whichever system is selected, the system is made up of several components. The multicomponent facet leads to an optimization problem, since many different combinations could be chosen. Because of this, a detailed laboratory screening procedure is necessary and typically involves three types of tests for: (1) phase behavior; (2) interfacial tension; and (3) oil displacement.
Phase behavior tests are typically conducted in small (up to 100 mL) vials in order to determine what type, if any, of microemulsion is formed with a given micellar– crude oil system. The salinity of the micellar solution is usually varied around the salt concentration of the field brine where the process will be applied. Besides the microemulsion type, other factors examined could be oil uptake into the microemulsion, ease with which the oil and aqueous phases mix, viscosity of the microemulsion, and phase stability of the microemulsion. Interfacial tension tests are conducted with various concentrations of micellar solution components to determine the optimal concentration ranges.
The oil displacement tests are usually conducted using two or more types of porous media. Often initial screening experiments are conducted in unconsolidated sand packs and then in Berea sandstone. The last step in the sequence is to conduct the oil displacement experiments in actual cored samples of reservoir rock. Frequently, core samples are placed end to end in order to obtain a core of reasonable length since the individual core samples may be only 5 to 7 inches long.

2.2.3.3 Miscible enhanced oil recovery (Gas Drive Oil)

Gas injection or miscible flooding is a general term for injection processes that introduce miscible gases into the reservoir. A miscible displacement process maintains reservoir pressure and improves oil displacement because the interfacial tension between oil and water is reduced. This refers to removing the interface between the two interacting fluids. This allows for total displacement efficiency.
Gases used in this process include CO_2, natural gas or nitrogen. The fluid most commonly used for miscible displacement is carbon dioxide because it reduces the oil viscosity and is less expensive than liquefied petroleum gas. Oil displacement by carbon dioxide injection relies on the phase behavior of the mixtures of that gas and the crude – these behaviors are strongly dependent on reservoir temperature, pressure and crude oil composition.

As oil and gas have a cognate symbiosis in the same structural trap, their physical and chemical properties are similar. As such, the Gas Drive Oil method has the potential to deliver better displacement process efficiency and higher recovery rates than other techniques. However, this theory is relevant only under specific reservoir conditions. If these specific conditions are present, then the volume expansion of the injected gas which acts to move the oil, takes precedent over the smaller chemical reactions from the gas drive process at the oil and gas interface.

2.2.3.3.1 Carbon Dioxide Flooding

When a reservoir's pressure is depleted through primary and secondary production, carbon dioxide flooding can be an ideal tertiary recovery method. It's particularly effective in reservoirs deeper than 2,000ft., where CO2 will be in a supercritical state.

Carbon dioxide flooding works on the premise that by injecting CO2 into the reservoir, it dissolves in oil, the oil swells and the viscosity of any hydrocarbon will be reduced and hence, it will be easier to sweep to the production well.
If an existing well has been designated suitable for CO2 flooding, the pressure within the reservoir must first be restored to that of one suitable for production by injecting water (with the production well shut off) (**Fig. 2-10**).

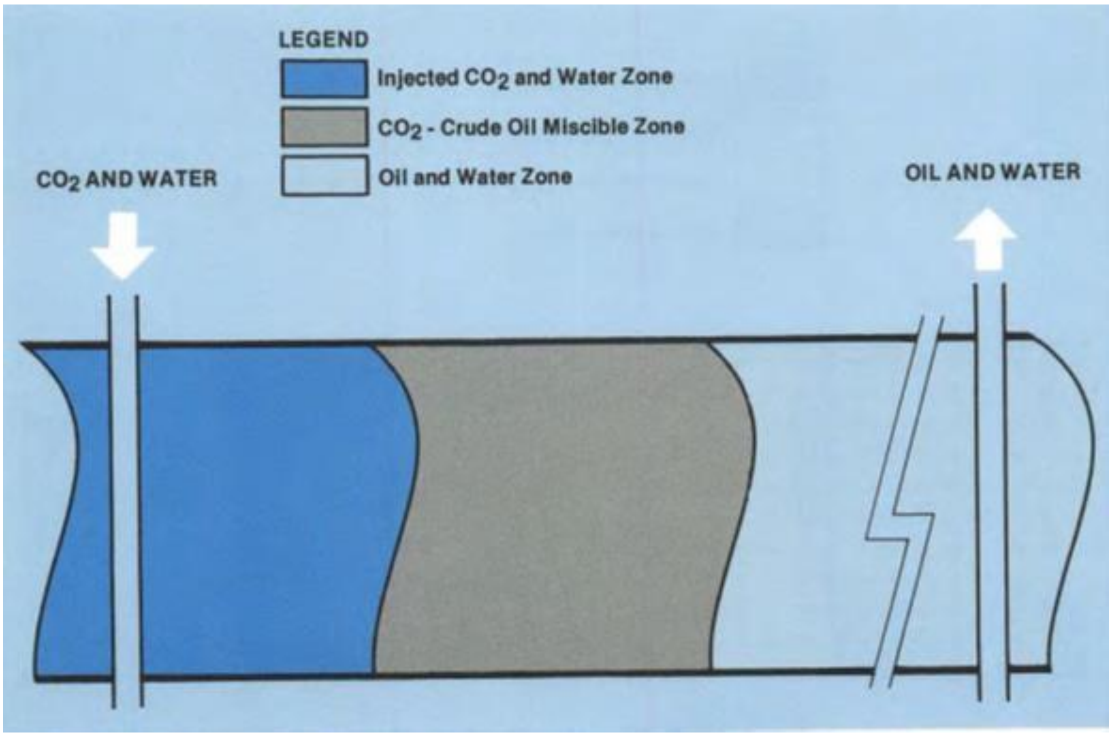

Fig 2.10: Carbon Dioxide Flooding process

Once the reservoir is at this pressure, liquid CO2 is injected into the same injection wells used to restore pressure to generate H2CO3, soluble Ca and Mg ionic components in the reservoir. The CO2 gas is forced into the reservoir and is required to come into contact with the oil.
This creates a miscible zone that can be moved more easily to the production well. Normally the CO2 injection is alternated with more water injection, with the water acting to sweep the oil towards the production zone.

In these applications, between one-half and two-thirds of the injected CO2 returns with the produced oil. This is then usually re-injected into the reservoir to minimize operating costs. The remainder is trapped in the oil reservoir by various means. Carbon dioxide as a solvent has the benefit of being more economical than other similarly miscible fluids such as propane and butane. This type of technology can be good to enlarge volume and improve recovery efficiency, but unless natural CO2 exists in the neighborhood area, it's generally difficult to collect sufficient amounts of CO2 for industry use.

2.2.3.4 Microbial

Microbial enhanced oil recovery (MEOR) processes involve the use of reservoir microorganisms or specially selected natural bacteria to produce specific metabolic events that lead to enhanced oil recovery. The processes that facilitate oil production are complex and may involve multiple biochemical processes. Microbial biomass or biopolymers may plug high-permeability zones and lead to a redirection of the water flood, may produce surfactants that lead to increased mobilization of residual oil, may increase gas pressure by the production of carbon dioxide, or may reduce the oil viscosity due to digestion of large molecules.

These days there is also a new biological theory which involves injecting bacteria into the oil reservoir to improve the recovery efficiency. Experimental results using a particular species in a reservoir have shown that through the metabolism of large population, large amounts of organic acids can be produced. These organic acids may act to restore vitality to an aging well, increase it from a microbiologist's perspective, microbial enhanced oil recovery.

processes are somewhat akin to in situ bioremediation processes. Injected nutrients, together with indigenous or added microbes, promote in situ microbial growth and/or generation of products that mobilize additional oil and move it to producing wells through reservoir repressurization, interfacial tension/oil viscosity reduction, and selective plugging of the most permeable zones. Alternatively, the oil-mobilizing microbial products may be produced by fermentation and injected into the reservoir. productivity and thereby act to induce a substantial increase in oil recovery.

Three approaches have been used to achieve microbial injection. In the first approach, bacterial cultures mixed with a food source (a carbohydrate such as molasses is commonly used) are injected into the oil field.

In the second approach, used since 1985, nutrients are injected into the ground to nurture existing microbial bodies. These nutrients cause the bacteria to increase production of the natural surfactants they normally use to metabolize crude oil underground. After the injected nutrients are consumed, the microbes go into near-shutdown mode, their exteriors become hydrophilic, and they migrate to the oil-water interface area where they cause oil droplets to form from the larger oil mass. This then makes the oil droplets more likely to migrate to the wellhead.

The third approach is used to address the problem associated with the paraffin wax components of the crude oil, which tend to precipitate as the crude flows to the surface. Since the Earth's surface is considerably cooler than the petroleum deposits, a temperature drop of 9-10-14 °C per thousand feet of depth is usual.

Microbial injection is part of microbial enhanced oil recovery and is rarely used because of its higher cost and because the developments are not widely accepted. These microbes' function either by partially digesting long hydrocarbon molecules and generating bio-surfactants, or by emitting carbon dioxide, which then functions as described in Gas Injection above.

One of the major attributes of microbial enhanced oil recovery is its low cost, but there must be recognition that it is a single process. Furthermore, reports on the deleterious activities of microorganisms in the oil field contribute to the skepticism of employing technologies using microorganisms. It is also clear that scientific knowledge of the fundamentals of microbiology must be coupled with an understanding of the geological and engineering aspects of oil production in order to develop microbial enhanced oil recovery technology. Finally, recent developments in upgrading of heavy oil and bitumen indicate that the near future could see a reduction of the differential cost of upgrading heavy oil. These processes are based on a better understanding of the issues of asphaltene solubility effects at high temperatures, incorporation of a catalyst that is chemically precipitated internally during the upgrading, and improvement of hydrogen addition or carbon rejection.

2.3 EOR Project Planning

Successful EOR project management depends on good planning – "prior proper planning prevents poor performance", they say, and it's especially true when EOR is involved. From the outset careful attention to economics and modeling at every step greatly improves the chances of success. We have all been involved in EOR developments where considerable time and effort was spent on projects that had no hope of achieving adequate profitability. Early screening studies would have clearly identified the problem and avoided a great deal of pointless engineering work.

Process selection begins with the identification of a target volume of hydrocarbons not accessible by primary or secondary means. This identification requires answers to the following questions:

1) What is the remaining hydrocarbon in-place after conventional methods?
2) Where is this resource located?
3) What is the reason it has not been recovered?

The determination and confirmation of the target volume and location is a critical first step in process selection. In order to answer these questions, a body of information about the characteristics of both the reservoir and the reservoir fluids is necessary. Geological analysis and dynamic modeling, addressed later herein, can help answer these questions, but should if possible be supported by field data: core analyses, fluid properties measurement, and detailed production history and pressure information.

Screening will result in a few candidate processes; selection requires that the specific target reservoir be matched to the specific process. This is not wholly a technical question; the economic viability of the project will depend on the matching process. For any EOR process: Can the process selected be used in the selected reservoir, given the reservoir rock and fluid environment in place? Can this process be implemented in such a way that it will result in an economically attractive project?

The answers to the above questions are critical in the final selection of a process, and must be carried out in conjunction with geological and laboratory investigations, as well as with project economic analysis and project design.

2.3.1 Geologic Studies

A good understanding of the reservoir geology is critical to the success of an EOR project. Because it is vital to contact remaining oil-in-place with the injecting, the geological understanding should be in sufficient detail to allow modeling of these complicated processes. In most cases, the reservoir will have sufficient production performance so that a history match can be obtained. This will not necessarily provide a sufficient geological description for EOR purposes. In EOR, movement of injecting through a thief zone, causing premature breakthrough, or loss of injecting out of zone, may result in failure of the project. Mineralogy of the reservoir, by determining the amount of adsorption of injecting (in the case of polymer and chemical methods), will dictate the amount of injecting necessary for success. A detailed geologic study should precede any EOR effort. This study should

at a minimum revisit all logs, core and fluid data, as well as result in a detailed geologic model that provides a satisfactory history match to production performance.
In addition, reservoir fluid and core samples should be obtained and analyzed, and the data specific to the EOR method to be used for project design identified and gathered. If a pilot is intended, data should be gathered in the pilot area, and detailed geologic modeling carried out specific to the pilot.

2.3.2 Modeling

The modeling of EOR projects requires that the reservoir description used for conducting reservoir simulation studies be consistent with the geological model, and validated with pre- EOR reservoir performance, and requires much more data and time than scale-up techniques and waterflood secondary recovery project design studies. The modeling of EOR projects is basically a five-step procedure: (1) selection of an appropriate reservoir simulator for conducting the project design study, (2) collecting valid input data, (3) history matching past production-pressure performance of the reservoir, (4) predicting future EOR project performance, and (5) determining the optimum EOR project design, by conducting sensitivity studies.
The procedure for selecting an appropriate reservoir simulator for conducting an EOR project design study involves selecting a black oil or modified black oil/pseudo-compositional or fully compositional or thermal simulator that will accurate predict the performance of the reservoir under the EOR processes to be simulated. Since most producing companies these days use commercially available reservoir simulators, selection of a reservoir simulator involves not only comparing which of the commercially available simulators are known to be bug free, have the necessary and user-friendly pre- and post-processing interfaces, and run fast on the types of reservoirs and EOR processes to be simulated, but also the record/reputation of the software vendor in providing technical support whenever necessary to ensure that the reservoir simulation studies can move forward smoothly and the project can be completed in a timely manner.

2.3.3 Economics

For EOR projects, as in all E&P projects, the primary economic driver is project profitability, in most cases. Will the project meet the necessary economic criteria, and what are the conditions under which this will occur? In some cases, development of a reliable production stream, reserves additions, or employment related to project longevity

might also be considerations. The economics of an EOR project are closely linked to the technical design of the process. Economic analysis should be carried out in tandem with the process screening and process selection steps, progressing from simple to progressively more complex analyses.
Once the target oil volume is determined, and process screening has resulted in the choice of a few options on a technical basis, economic screening should be done. At this stage, the critical parameters may be the slug size and cost of the EOR injecting. Using a range of During the screening step, it is essential that the range of uncertainty in both the reservoir parameters and the process parameters be recognized and considered. The process should be evaluated using optimistic assumptions for those parameters for which a range of uncertainty exists. At this stage, the effort should be to identify the critical technical factors that impact the project, so that subsequent efforts may be focused on those elements, which most impact the project viability. Included in this are assumptions regarding the timing and operation of the project; thus, simple process modeling using parameters of the field project in reservoir simulations will guide the economic analysis and the process selection path forward's subsurface parameters, project economics can be estimated. Once the process has been selected, both the technical and economic effort will be focused on those aspects of the project, which have been identified as critical to success. This effort will use the results of laboratory investigations and field-testing, incorporated into more detailed reservoir geological and simulation models, to better characterize the project and its viability.
The economic analysis is critical to the success of an EOR project, by identifying the critical technical parameters that govern the project's profitability and providing the justification to carry out the necessary work to confirm assumptions, modify the process, and optimize the results. It should be an integral part of the project design and development process.

2.3.4 Design Parameters

The specific EOR process to be implemented will determine the project design parameters that are critical. Design must be carried out on the micro scale, as well as the macro scale. On the micro scale, the parameters that determine an efficient displacement must be specified. In the case of a miscible project, for example, results from detailed laboratory tests of miscibility pressure and multiple contact experiments will be used to determine the optimum displacement of hydrocarbons.

In chemical processes, adsorption experiments will determine the rock-slug interaction, and phase behavior studies and surface tension measurements will allow design of the displacement process.

2.3.5 Pilots

There is a misconception that it is necessary, for technical reasons, to carry out a field pilot of any EOR process. This is not true. For example, if there is sufficient analogue experience, and the reservoir geology is understood, modern simulation methods may be reliable enough to make a pilot test unnecessary. A second misconception is that an "oil in the tank" pilot is sufficient to be able to predict performance on a field scale. Such pilots are almost always not sufficient to make a reliable extrapolation to a full-scale project.

The question should be: “what are the critical unknowns that may cause a material difference in the response of the project?” These critical parameters should be known from the sensitivity studies done in the process selection and design steps, and their accompanying economic analyses and reservoir modeling. If it is concluded that uncertainties in the key parameters are critical in determining the project’s viability, and that these uncertainties cannot be resolved in the laboratory or through modeling, then a pilot test should be considered to reduce those uncertainties. The pilot should then be designed to obtain the key information necessary. The pilot should be able to provide the quantitative information needed to calibrate models to predict commercial performance, and to reduce the project risk to acceptable levels. Pilot tests may range from a simple infectivity test to a full multipattern injection and production test. Pre- and post-test cores may be needed; logging and sampling observation wells and other data gathering methods may be necessary. A good understanding of the geology of the site, as well as dedicated production and injection wells, is critical to the success of a pilot.
Any pilot test should be specifically designed to obtain the key data required to better make a project decision. An appropriate test site, dedicated personnel, facilities, and wells are required, along with a commitment to use these resources to design, implement and carry the pilot to its conclusion. Thus, a pilot test must also be staffed with appropriate personnel, and have effective surveillance and post-test analysis carried out, in order to add value to the project.

2.3.6 Project Implementation

The project design will include in its recommendations for data gathering and surveillance activities, as well as operational guidelines and quality control specifications which will be essential to its success. Good installation and implementation of a project, following the guidelines and recommendations is likewise essential to its success. Prior to project startup, field personnel must be trained in the project’s purpose and operations. An EOR project does not represent “business as usual” in the oil field. A detailed project management document should be developed, detailing both the project expectations and the surveillance activities to be carried out during the life of the project. Included should be scheduled well and project reviews on a regular basis.
Recommended surveillance may include taking of pressure or temperature data in observation wells, obtaining production fluid samples, carrying out quality control activities on injection fluid facilities, as well as the normal field operations activities. The use of a suite of reservoir simulation models which encompass the range of uncertainties in the process and project, as part of the normal reservoir management and surveillance process, will provide the ability to incorporate the data gathered and diagnose the behavior of the project. These models should be extensions of those used for project design, to provide a tie to the original project justification.
EOR is a technique, which can provide significant increases in recovery from a reservoir, but those increases depend on appropriate process selection, good project design, recognition and addressing of critical uncertainties, and attention to details in the implementation and management of the project.

CHAPTER THREE

3. METHODOLOGY

3.1 Introduction

This chapter deals with the methodology and the major directions of this research. The main purpose of the project is to define the most proper thermal EOR method to obtain the maximum oil recovery from AL-ROIDHAT field. This chapter illustrates some types of screening criteria used to evaluate the optimum thermal EOR method according to specific conditions and parameters for each method. Then EOR is chosen to this case study depending on the availability of screening tool and data required.

3.2 Type of data that needed for the project

1. **Alteration** in the fluid properties in situ such as the comprise changes in phase behavior and PVT data.
2. **Rock properties** such as absolute permeability, porosity, rock compressibility, and the attendant changes in these properties on the injection.
3. **Properties related to fluid-rock interaction**. These include residual saturation (related in turn to wettability, interfacial tension, etc.), relative permeabilities, capillary pressure, and their dependence upon temperature.
4. **The reservoir environment:** net/gross ratio (presence of shale barriers, etc.), heterogeneity, properties of the overburden and underburden, the initial oil saturation, temperature, and pressure.
5. **Flood geometry:** producing-injecting interval (well completion) location and thickness.
6. **Thermal properties** of the formation and the contained fluids, such as specific heats, thermal conductivities, thermal expansion coefficient, and the changes induced in these.
7. **Parameters within the operator's control**, such as steam injection rate, steam quality, injection pressure (temperature), cumulative amount of injection.

3.3 The nature and sources of data used in the EOR process

Through consideration, scrutiny and study of the reservoir properties and nature of oil located in the field to be conducted study, and knowledge of the most important characteristics to be studied for the process of selection of the appropriate EOR project. Therefore, it requires us to know from which report or source these characteristics were obtained and where they will be used based on the extent of the project. Therefore, the data used for this purpose can be divided from our point of view into two main parts:

3.3.1 Heavy oil properties

The most important properties of oil we have in the reservoir to be studied. There are several characteristics under this item, but the most important that we will need in this project are summarized as follows (API Gravity, Viscosity, Oil composition). We can get the data of these characteristics through several field reports have been working in the same field and the most important (PVT data).

3.3.2 Rock Properties (Reservoir)

Under this title, there are many characteristics of interest to many development projects, production improvement and others. We must identify the most important characteristics that concern us in this aspect, which requires us to achieve and identify the most important characteristics of the selection EOR process, (Depth, Temperature, Average permeability, Pay thickness, Formation Type, oil saturation). The values of these characteristics can be obtained from several specialized agencies, the most important of which are:

a. Formation Type, pay thickness and Depth can be obtained from wireline data or final drilling report.

b. Average permeability can be obtained from final test report. C- Temperature, oil saturation can be obtained from PVT data.

3.4 Analysis approach

There are several methods that are used in the examination process, through which the appropriate method is chosen from the EOR methods. It should be noted here that most of the methods used in this area is very complex depending on the basis on which each method and the conditions of implementation and analysis. It should also be noted that these methods range from the level of ease of use and some kind of available to the level of difficult to use and unavailable or rely on very complex analysis, which takes several years to use. We refer here to the most frequently used methods and will select the best available method from them, the selected one which have been chosen for the project is Taber method.

3.5 TABER Method:

The choice of EOR methods to specific conditions is one of the most difficult tasks for a reservoir engineer. One of the methods, which offered technical screening, guides for EOR nowadays known as Taber's tables. It is one of the widely cited publications in petroleum engineering for EOR criteria. This method was introduced in 1996 by calibrating standards for several field experiments around the world to achieve success in the oil industry. These tables consisted of 12 EOR methods tabulated a giants 10 reservoir properties, which classified into oil properties and reservoir characteristic field. Both oil properties and reservoir characteristic are considering as a guideline for selection the suitable EOR method.
The EOR criteria published by Taber and colleagues (1996) was updated to include EOR survey reports submitted from 1998 through 2010. The updates to the EOR criteria include the addition of the entire range of oil and reservoir properties for all EOR methods, a reservoir fluid property, namely, porosity, and permeability and depth ranges

for miscible and immiscible gas EOR methods because of their importance. New categories and subcategories of EOR methods also were added to the EOR criteria, including the categories of microbial EOR, miscible WAG, and hot water flooding, as well as the immiscible gas flooding subcategories of CO2, nitrogen and WAG. Furthermore, the new criteria include the number of EOR projects (the number of datasets) to provide an impression of the confidence level used for each EOR method to derive the EOR selection criteria. As a result, the number of EOR in Taber methods has been expanded from 12 to 16.

Table 3-1 TABER table:

Oil Properties						Reservoir Characteristics					
SN	EOR Method	Projects	Gravity (API)	Viscosity (cp)	Porosity %	Oil Saturation (% PV)	Formation Type	Permeability (md)	Net Thickness	Depth (ft)	Temperature (°F)
Miscible Gas Injection											
1	CO2	139	28(22)-45 Avg 37	35-0 Avg 2.1	3-37 Avg 14.8	15-89 Avg 46	sandstone or carbonate	1.5-4500 Avg 201.1	(wide Range)	1500-13365 Avg 6171.2	82-250 Avg 136.3
2	Hydrocarbon	70	23-57 Avg 38.3	18000-0.04 Avg 286.1	4.25-45 Avg 14.5	30.98 Avg 71	sandstone or carbonate	0.1-5000 Avg 726.2	(Thin unless dipping)	4040(4000)-15900 Avg 8343.6	85-329 Avg 202.2
3	WAG	3	33-39 Avg 35.6	0.3-0 Avg 0.6	11-24 Avg 18.3		sandstone	130-1000 Avg 1043.3	(NC)	7545-8887 Avg 8216.8	194-253 Avg 119.4
4	Nitrogen	3	38(35)-54 Avg 47.6	0.2-0 Avg 0.07	7.5-14 Avg 11.2	0.76(0.4)-0.8 Avg 0.78	sandstone or carbonate	0.2-35 Avg 15.0	(Thin unless dipping)	10000(6000)-18500 Avg 14633.3	190-325 Avg 266.6
Immiscible Gas Injection											
5	Nitrogen	8	16-54 Avg 34.6	18000-0 Avg 2256.8	11-28 Avg 19.46	47-98.5 Avg 61	sandstone	3-2800 Avg 1041.7		1700-18500 Avg 7914.2	82.325 Avg 173.1
6	CO2	16	11-35 Avg 22.6	592-0.6 Avg 65.5	17-32 Avg 26.3	42-78 Avg 56	sandstone or carbonate	30-1000 Avg 217		1150-8500 Avg 3385	82.198 Avg 124
7	Hydrocarbon	2	22-48 Avg 35	4-0.25 Avg 2.1	5-22 Avg 13.5	75-83 Avg 79	sandstone	40-1000 Avg 520		6000-7000 Avg 6500	170-180 Avg 175
8	Hydrocarbon + WAG	14	9.3-41 Avg 31	16000-0.17 Avg 3948.2	18-31.9 Avg 15.09	Avg 88	sandstone or carbonate	100-6600 Avg 2392		2650-9199 Avg 7218.71	131-267 Avg 198.7

Oil Properties						Reservoir Characteristics					
SN	**EOR Method**	**Projects**	**Gravity (API)**	**Viscosity (cp)**	**Porosity %**	**Oil Saturation (% PV)**	**Formation Type**	**Permeability (md)**	**Net Thickness**	**Depth (ft)**	**Temperature (°F)**
Chemical Methods											
9	Polymer	53	13-42.5 Avg 26.5	4000-0.4 Avg 123.2	10.4-33 Avg 22.5	34-82 Avg 64	sandstone	1.8-5500 Avg 834.1	NC	700-9460 Avg 4221.9	74-327.2 Avg 167
10	Alkaline Surfactant Polymer (ASP)	13	23(20)-34(35) Avg 32.6	6500-11 Avg 875.8	26-32 Avg 26.6	68(35)-74.8 Avg 73.7	sandstone	596 (10)- 1520	NC	2723-3900(9000) Avg 2984.5	118(80)- 158(200) Avg 121.6
11	Surfactant + P/A	3	22-39 Avg 31	15.6-3 Avg 9.3	16-16.8 Avg 16.4	43.5-53 Avg 48	sandstone	50-60 Avg 55	NC	625-5300 Avg 2941.6	122-155 Avg 138.5
Thermal/Mechanical Methods											
12	Combustion	27	10-38 Avg 23.6	2770-1.44 Avg 504.8	14-35 Avg 23.3	50-94 Avg 67	sandstone or carbonate (preferably carbonate)	10-15000 Avg 1981.5	(>10)	400-11300 Avg 5569.6	64.4-230 Avg 175.5
13	Steam	271	8-30 AVG 14.5	5E6-3 Avg32971.3	12-65 Avg 32.2	35-90 Avg 66	sandstone	1-15000 Avg 2605.7	(>20)	200-9000 Avg 1643.6	10-350 Avg 105.8
14	Hot Water	10				15-85 Avg 58.5	sandstone	900-6000 Avg 3346	-	500-2950 Avg 1942	75-135 Avg 98.5
Microbial											
15	Microbial	4	12-33 Avg 26.6	8900-1.7 Avg 2977.5	12-26 Avg 19	55-65 Avg 60	sandstone	180-200 Avg 190	-	1572-3464 Avg 2445.3	86-90 Avg 88

3.5.1 Mechanism of Taber Method:

The mechanism is Done by matching data available with Taber tables in terms of data and parameters which each table has limitations. The EOR selection criteria categorize EOR methods into gas, chemical and thermal and are based on a range of reservoir properties listed for each of these methods. Also includes the limitations of each EOR method. The EOR selection criteria were based on a range of reservoir properties (table 3.1) without considering incremental recovery or the project's distribution scale. Despite the implementation of over 600 EOR projects since
1959 (The Oil and Gas Journal, (OandGJ), 1998-2008). The development and implementation of any recovery methodology, especially on a field-wide scale, requires confidence in its efficacy. Establishing such confidence requires an in-depth analysis of EOR projects that would provide updated and more concise EOR selection criteria.

3.6 EXPECTED RESULTS

Based on previous studies conducted using this method and based on matching reservoir properties of the formation and liquid of these studies with the characteristics of the target field to be studied and based on data available and environmental indicators we can say that in the case of the ideal application of this method in ALROIDHAT fields in Block 9, we can expect the following:

1. Increase in the reservoir temperature.
2. Decrease in the oil viscosity.
3. Rebuild the formation pressure and help drive mechanism in the reservoir.
4. Increase the productivity and increase in the rate of oil production.
5. Increase the recovery factor.

CHAPTER FOUR

4.RESULT AND DISCUSSION

4.1Introduction

This chapter explain the usage of the methodology for selecting the type of the thermal EOR by analysis and comparison process according to the data that has been collected from the previous chapters, beside explaining the type which is selected, also compare that type which is applied and used in another field with Al-Roidhat field and discuss the enhancement that could be approach.

4.1.1 Selecting thermal EOR Method based on Taber Method

By using Taber method in chapter three we have compared the petrophysical properties of the field with the thermal EOR method and figure out the suitable method to enhance the production of Al-Roidhat field in an economic way.

4.1.2 Liquid properties (Oil)

the liquid properties which are taken in the process of selecting the suitable method of thermal EOR are summarized in **Table 4-1**:

Table 4-1 Liquid Properties of Al-Roidhat field

Property	Al-Roidhat field
API Gravity	14.2
Viscosity cp	420

4.1.3 Rock properties (Reservoir)

The reservoir parameters which are required to correlate with **Taber tables** in the process of choosing the appropriate method for EOR are shown in **Table. 4-2**. Carefully these values were obtained in order to ensure the suitable decision to the enhance method.

Table 4-2 Rock properties of Al-Roidhat Field

Property	Al-Roidhat field
Oil Formation Volume Factor, stb/bbl	1.03
Porosity, %	21
Oil Saturation, %	68
Formation Type	Sandstone
Permeability, md	250
Net Thickness, ft	115
Depth, ft	3402-3517
Temperature ,^{5}F	122-137

After comparing the previous values with those specified in TABER tables, see chapter 3. It has been proven that the most suitable enhance methods for use in Al-Roidhat field in order to process heavy oil in the reservoir and increase production are the **Thermal Enhancement by Steam** methods. Through previous field studies conducted in reservoirs that are very similar to the properties present in this field, it was concluded that, the choice tends to use **steam injection.**

Table 4-3 Comparison Between Steam Method and Al-Roidhat Field

EOR Process	API Density	Porosity, %	Oil Saturation, %	Viscosity Cp	Formation Type	Net Thickness, ft	Depth, ft	Perm(K), md	Temp, F
Steam	**8 - 33 Avg. 14.61**	**12 - 65 Avg. 32.2**	**35 - 90 Avg. 66**	**>20**	**Sandstone**	>20	**200 - 9000 Avg. 1647**	**1 - 15000 Avg. 2669.70**	**10 - 350 Avg. 105.91**
Al-Roidhat	**14.2-15**	**21**	69	**240-420**	**Sandstone**	115	**3402-3517**	**250**	**122-137**

4.1.4 Selection of Steam Stimulation Method

The next step is selecting the suitable steam method by matching its parameters with Al-Roidhat field. By the researches we've done and by comparing the Al-Roidhat field characteristics with many fields around the world to find the fitted and matched one, the nearest candidate field for the comparison is **FULA NORTH FIELD** which has properties similar to our field, as seen in **Table 4-4**. The field is in Sudan and the project had been applied Cyclic Steam Injection, thus by seeing the successful results of that project, we figure out that CSS would be the selected method for our project and through that we build up our assumptions, calculation, and comparison to find the result we need.

Table 4-4 Comparison Al-Roidhat Field with Fula North Field.

Property	Al-Roidhat field	Fula North Field
Oil Formation Volume Factor, (stb/bbl)	1.03	0.9759
Porosity, %	21	25
Oil Saturation, %	68	70
Formation Type	Sandstone	Sandstone
Reservoir Depth (ft)	3500	3120
Net Thickness, ft	115	93.6
Viscosity (cp)	472	727
Temperature, (F)	122-137	122

To ensure that CSS is the best choice for the project, another comparison between the CSS parameters with Al-Roidhat field properties have been applied see **Table 4-5.**

Table 4-5 comparison between CSS method and Al-Roidhat Field

Parameters	Desirable Extent (CSS)	Al-Roidhat Field
Oil API Degree	10 – 27	14 -15
Viscosity (cp)	<50000	240 – 420
Oil Saturation (pv%)	>60	69
Net Thickness(ft)	>10	115
Reservoir Rock type	Sand or Sandstone with high porosity	Sandstone
Permeability(md)	>100	250
Depth(ft)	>500	3500
Temperature(F)	>120	137

4.2 Applying Cyclic Steam Stimulation

Cyclic steam stimulation (or cyclic steam injection) is the alternating injection of steam and production of oil with condensed steam from the same well or wells.

Cyclic steam stimulation consists of the injection of a modest amount of steam into a well, followed by a period of production from the same well. The process is repeated as and when required, hence the process name cyclic steam stimulation. The mechanism that aids the production of the oil is the flushing of hot water back to steam as the pressure is lowered during production. This process is predominantly a vertical well process, with each well alternately injected with steam and producing heavy oil and steam condensate.

4.2.1 Advantages

- It requires only one wellbore reducing capital investment.
- It is a proven technology.
- Very useful when reservoir is disconnected.
- The reaction behavior for production occurring by quicker rate.
- Less impact towards the environment.
- The heat is getting by the injected steam adjacent the wellbore where the streamline becomes closer and the pressure gradients becomes higher.
- CSS is a flexible technique that it’s dealing with a large area of reservoir conditions.
- Minimizing the well numeration which leads to decrease the initial capital costs of CSS.
- Reduce operation’s power.
- The heat conservation of oil which is subjected to hot steam even after it reaches and crosses the production wells.

4.2.2 Application of CSS in some field

In practice, steam is injected into the formation; this is followed by a soak period and production (Burger, 1978; Winestock, 1974). The technique has also been applied to the California tar sand deposits (Bott, 1967) and in some heavy oil reservoirs north of the Orinoco deposits (Ballard et al., 1976). The steam flooding technique has been applied, with some degree of success, to the Utah tar sands (Watts et al., 1982) and has been proposed for the San Miguel (Texas) tar sands (Hertzberg et al., 1983).California’s Kern River production rose from less than 20,000 barrels per day in the late 1950s before cyclic steam stimulation to over 120,000 barrels per day by 1980 after the introduction of cyclic steam stimulation. The Duri field in Indonesia is the world’s largest steam flood and produces 230,000 barrels per day.

4.2.3 Cyclic Steam Stimulation (EOR) Process

4.2.3.1 Injection phase

It’s the first step which by it a cycle of CSS begins to operate. So as previously noted, an amount of hot steam must be injected into a certain well (it doesn’t matter horizontal or vertical) for a small duration. Then a chamber is generated from that injected steam for pressure maintenance in the formation to make a pressure build-up facing the pressure of the injected steam.

As everyone knows, it has become a truism that the Temperature is directly proportional with the viscosity especially in liquids. That means by the increment of the reservoir temperature, the viscosity of the crude is always decreases which helps in getting more initial oil rate. In addition, an augment in the oil velocity is noticed due to a rising in the reservoir pressure adjacent the wellbore.

While this phase “injection phase”, the steam saturation degree of temperature is put equal to the average temperature of the chamber which is formed by the injected steam. After this degree is reached the injection period has been stopped and the soaking period is had to start by closing the well for a while until the chamber of the steam is created and the temperature is begun to rise.

4.2.3.2 Soaking phase

This is the shut-in period in the CSS cycle for the preparing and fulfillment of the injection goals and objectives. During soaking, the well is closed for a certain short duration which is selected precisely making the chamber expands by extending of the steam and allowing the steam to reach to further possible point in the formation to heat a bigger possible area.

Due to the gravity segregation the chamber of the steam and the crude oil after the heat distribution takes place to decrease crude viscosity. Surely the lighter component will raise upwards and another one will force to drop downwards because of its density. Therefore, the heavier component “oil” will go downwards while the steam which is the lighter one floats up inside the reservoir due to gravity effect.

When looking from the side of heat transfer study, it can be logically considered that this segregation happened by convection process between two fluids with different densities aiming in the enhancement of the whole process. The soaking time is a sensitive phase affected by the fluid's properties and it's an achievement step to the injection phase. As the soaking period decreases, the ratio of the produced oil to that oil in place increases.

4.2.3.3 Production phase

This phase is the last phase in a single CSS cycle. It comes directly after the small duration shut-in period "Soaking time". As noted earlier, the oil which is heated by the hot injected steam is forced to go down in the reservoir according to the density differences and gravity segregation effect and due to the variety in the pressures inside the well which will produce. After that, the well will start to produce this oil.

By the injection of the hot steam many zones have been heated and its degree of temperature will be large affecting in the initial oil rate which will become higher. By passage of time, more oil will be produced and that high degrees of temperature in the heated zone will decrease leading to the decline of that initial rate. Then the injected steam will again continue heating the oil which its temperature decreased and it became in a cold area in the zones which previously heated.

The increment of the temperature is followed by the decrement of viscosity of the crude oil which leads to a high enhancement in the oil producing rate when comparing with the production without CSS. The variety in pressures and the gravity segregation effect is combined together to represent the two-essential mechanism in the cyclic steam injection to induce oil.

In addition, the chamber of the steam which had been begun during the injection phase and completed in the Soaking period by the increment of the oil production continues expanding to compensate that produced oil and replaces it to conserve the reservoir energy.

4.2.4 Cyclic Steam Stimulation works best when

- The minimum depth for applying cyclic steam stimulation is on the order of 1,000 feet.

- Porosity should be no less than 20%.

- Thick pay zone is economical on reservoirs that contain pay zones more than 10 meters.

4.3 Preliminary Study on the Cyclic Steam application in Al-Roidhat Field.

4.3.1 The Work Plan Forward

1. Well Selection**:** to select a group of wells, open pilot test area.
2. Explaining the geological features and data available to choose the appropriate method of thermal EOR.
3. The method used is Cyclic Steam Stimulation.
4. Appropriate study on Cyclic Steam Stimulation.
5. Review of production characteristic and water cut

4.3.1.1 Well Selection

One well has been selected for pilot test (Al-Roidhat-1)

4.3.1.2 Geologic Features

1. Reservoir depth (3500 ft).
2. Net pay thickness (115 ft).
3. Reservoir characteristics: porosity (21%) and permeability (250 md).
4. Reservoir types: Sandstone.
5. The reservoir has 14.2 API and oil viscosity (420 cp).
6. Formation temperature: (122-137°F)
7. Drainage Area (30 acres)
8. Radius of drainage area (645 ft)

4.3.1.3 Production features

The (AR-1) well has:

-Production rate (380 bopd).

- Measure depth (3500 ft).

- Pressure less than (1140 psi).

4.3.1.4 Preliminary Economic Analysis on the Pilot Test Program

-Installation of steam generator and its accessories 800,000 USD.

-Installation of water recycle plant of 59,649 USD.

Total cost:

859,649 USD

4.4 Assumptions and Analysis for the Expected Results

At any system pressure and temperature, a liquid has some vaper pressure when the vaper pressure of the liquid equals the system pressure, this vaper pressure is the saturation pressure, and the corresponding temperature is the saturation temperature which means the boiling point.

According to reservoir conditions we assumed the injection pressure of steam to be (1300 psi) larger than reservoir pressure and lower than the fracture pressure of the formation (compared fracture pressure with fula sand field). Consequently, the saturation temperature will be 570°F and the enthalpy 1080 btu/Ib, see fig 4.1.

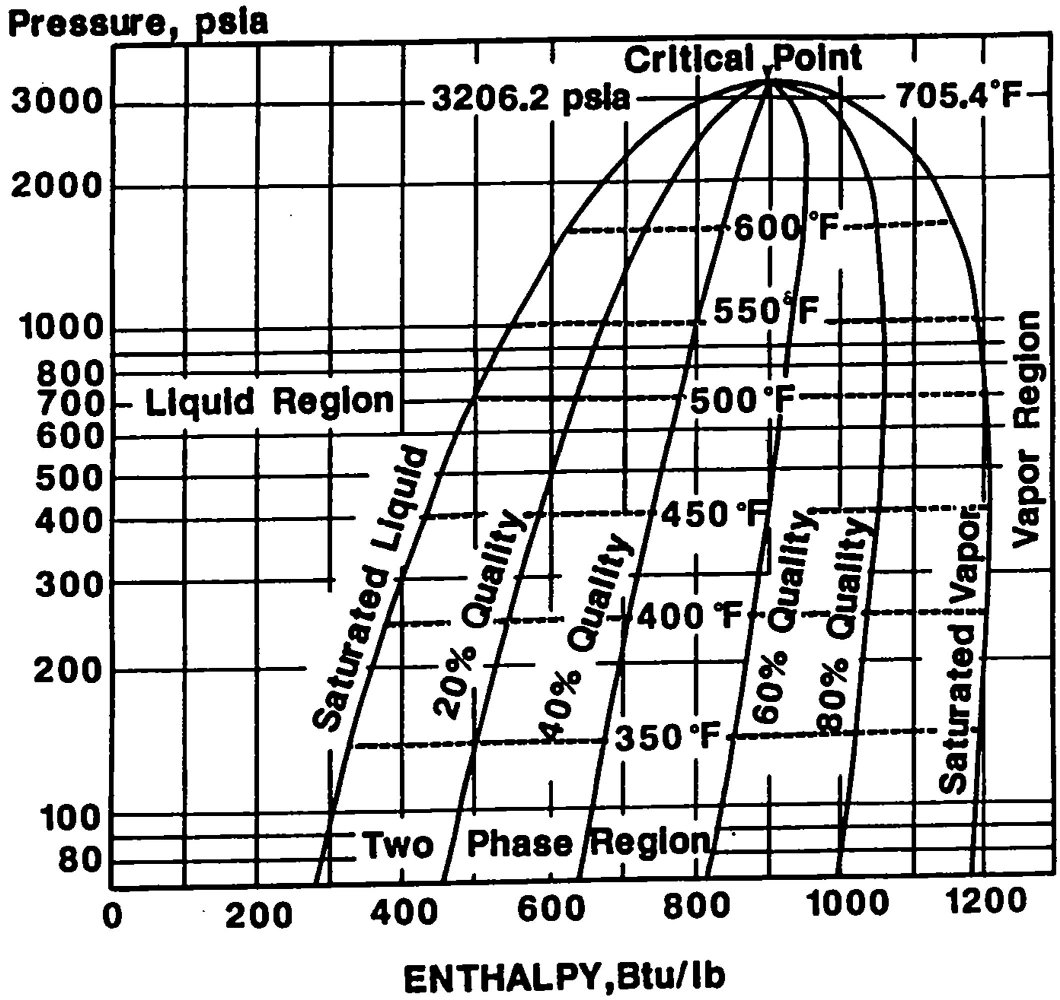

Fig 4.1: pressure-enthalpy chart of steam

Also, by matching, the enthalpy is 1080 Btu/Ib and the steam quality is 80%.

As an assumption, we've chose wet-steam generator with **25 MMBtu/hr** steam output, after that we calculated the capacity in Tons of steam per hour and saturation temperature of 25 MMBtu/hr of the wet-steam generator. Wet-steam generator operating pressure at 1300 psi and produce steam quality of 80%.

If 1 Ib mass of steam at 1300 psi saturation pressure has 1080 Btu then 1000 Kg or one Ton of steam is equal:

$$\mathbf{(1000Kg * 1080\ Btu/1\ Ib) / (0.4536Kg /1\ Ib) = 2.38*10^{6}\ Btu}$$

And

$$\mathbf{25MMBtu/hr = (25 * 10^{6}\ Btu/hr)/ (2.38 * 10^{6}Btu/Ton) = 10.50\ Tons/hr\ of\ steam}$$

So, the capacity of steam per day is 252 Tons.

Table 4-6 steam parameters

Parameter	Value
Injection rate (m^3/d)	252
Temperature (F)	570
Injection pressure (psi)	1300
Enthalpy (Btu/Ib)	1080
Heat capacity of reservoir (Btu/ft^2 - °F)	33.2

4.5 Evaluate and Explain the Expected Results

4.5.1 Increase reservoir temperature

The temperature increases due to high steam temperature that injected to the reservoir at a certain pressure and volume injection during injection periods, next formula showed that the temperature of the heating zone is 450-445°F

$$\Delta T = \frac{Ho*\Delta t}{Mr*h*\Delta A} \qquad (1)$$

The heat gained by steam is (H_o):

$$H_o = injection\, rate * enthalpy \qquad (2)$$

= 252 m^3/d * 1000 Kg/m^3 * 2.204 Ib/Kg * 1 day/24 hr * 1080 Btu/Ib

=24.3*10^6 Btu/hr

The change in area of steam zone

$$Area\ (\Delta A) = \frac{Ho*\Delta t}{Mr*h*(Ts-Tr)} \qquad (3)$$

The Injection time period

$$Time\ (t) = \frac{Mr*h*\Delta A*(Ts-Tr)}{Ho} \qquad (4)$$

The radius of the steam zone

$$Radius\ (r) = \sqrt{\frac{A}{\pi}} \tag{5}$$

Table 4-7 steam volume, radius, area and temperature.

Period (hr)	Stem volume (m^3/d)	Radius (ft)	Area (ft^2)	Temperature (°F)
9	94.5	6.38	128	450
24	252	10.56	350.64	448
120	1260	23.62	1753.20	448
240	2520	33.40	3506.41	448
480	5040	47.24	7012.83	447.9
552	5796	50.66	8064.75	447.8

4.5.2 Decrease in the viscosity of oil

Viscosity sometimes dramatically and large increases in the production rate can be predicted. A useful correlation of oil viscosity as a function of temperature and API gravity has been made by Farouq Ali and Meldau (1983) using viscosity-temperature data 60 heavy crude samples see fig 4.2 According to these studies the cyclic steam injection will tend to a rapid decrease in the viscosity of oil from 420 to 20.5 cp.

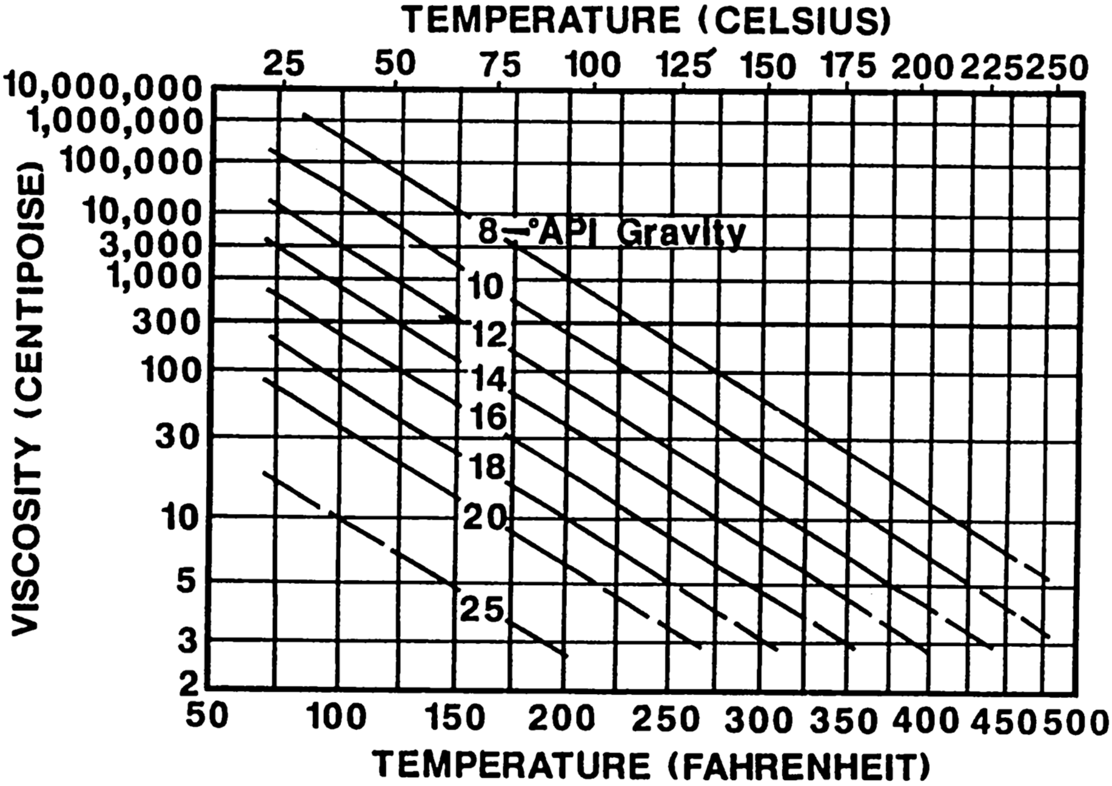

Fig 4.2: Relationship between of oil viscosity as a function of temperature and API gravity

4.5.3 Increase the productivity index

It is implied that the main mechanism of cyclic steam injection is the reduction in oil viscosity. Although removing damage does improve productivity,

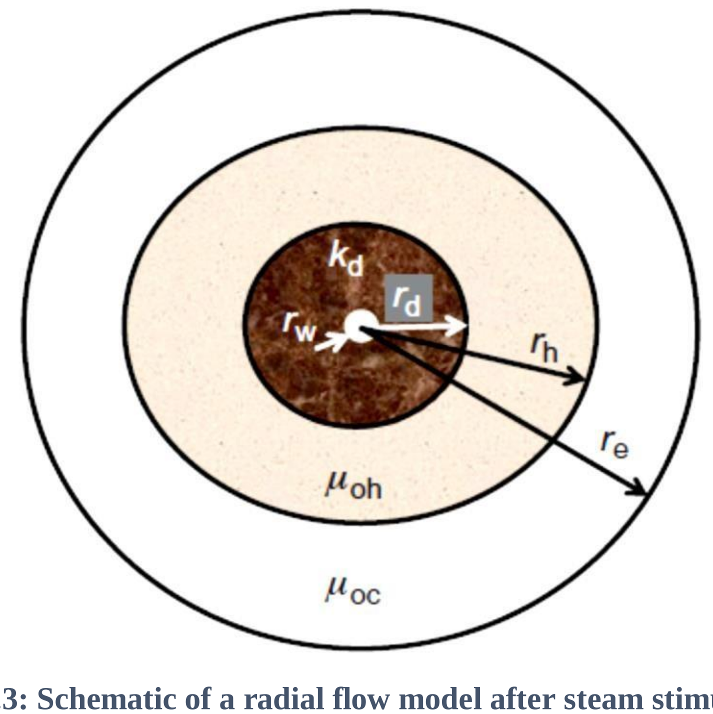

Fig 4.3: Schematic of a radial flow model after steam stimulation

Table 4-8 parameters of radial flow model after steam stimulation

r_w	r_d	r_h	r_e	μ_{oh}	μ_{oc}	$\frac{k_d}{k}$
0.7	6.4	50	645	20.5	420	1
Ft	Ft	Ft	Ft	Cp	Cp	----

The ratio of production index after steam stimulation (J_h) to that before (J_c) is

$$\frac{J_h}{J_c} = \frac{(k_d/k)\ log(r_e/r_d)+log(r_d/r_w)}{(k_d/k)\ \ log(r_e/r_h)+(k_d/k)(\mu_{oh}/\mu_{oc})\ \ log(r_h/r_d)+(\mu_{oh}/\mu_{oc})\ \ log(r_d/r_w)} \qquad (6)$$

$$\frac{\boldsymbol{J_h}}{\boldsymbol{J_c}} \approx 1.4$$

4.5.4 Increase the flow rate after steam stimulation can be calculate from this equation

$$\frac{J_{oh}}{J} = \frac{Q_{oh}}{Q} \qquad (7)$$

$$\boldsymbol{Q_{oh}} = \mathbf{380} * 1.4$$

$$\boldsymbol{Q_{oh}} = 530\ \boldsymbol{bbl/d}$$

Table 4-9 the input parameters for calculate Steam oil ratio:

D	**h**	**k**	**μ**	**S_o**
3500	**115**	**250**	**20.5**	**0.69**
Ft	**Ft**	**Md**	**Cp**	**%**

SOR is the ratio of unit of steam required to produce unit of oil. The typical values are three to eight and two to five respectively.

This means two to eight barrels of water converted into steam is used to produce one barrel of oil.

$$SOR = 18.744 + (1.453 * 10^{-3}\, D) - (50.88 * 10^{-3}\, h) - (0.8864 * 10^{-3}\, h) - (0.8894 * 10^{-3}\, k) - (0.591 * 10^{-3}\, \mu) - 14.79\, S_o - (0.2938 * 10^{-3}\, kh/\mu) \quad (8)$$

$$\boldsymbol{SOR} = 7$$

Table 4-10 the target results from the previous calculation:

J_h/J_c	Production flow rate after steam STB/day	Steam oil ratio
1.4	**530**	**7**

4.5.5 Increase Reservoir Recovery

The CSS has several mechanisms that contains many indicators of enhancing the recovery factor, it increases the reservoir temperature and thus reducing viscosity of the oil, by calculations done previously, the viscosity of the oil will decrease rapidly. Also, the thermal expansion in the heated zone increases the oil mobility and enhance its relative permeability.

The processes would make a noticeable incremental in recovery factor to an economic value of Al-Roidhat field.

CHAPTER FIVE

CONCLUSION, RECOMMENDATIONS, AND LIMITATIONS

In this project, a research for selecting criteria methods to select the best method of thermal EOR was done, thus the study was to match which one of them is suitable and fitted to enhance the heavy oil recovery in Al-Roidhat field in Block-9 (Masila), then after matching done by TABER screening criteria, the thermal EOR method have been chosen for the field is steam injection. Under the category steam injection in TABER, the Cyclic Steam Stimulation was found the appropriate method to be applied. Finely, the CSS was the project's recommendation to be performed in Al-Roidhat field.

5.1 Conclusion

5.1.1 Selecting the Thermal EOR Method

Selecting the thermal EOR method must be based in screening criteria methods, after the researches that done to find the best screening criteria that will lead us to choose the appropriate thermal EOR method, the methods vary, they have either some difficulties, or need programs, so the TABER method was found to be the best choice, due to its availability and the wide used for that method. The TABER tables are done as screening criterion in order to contribute the EOR selection. By comparing and matching the screening criteria of TABER with Al-Roidhat field characteristics, the thermal EOR method reached was Steam Injection. The Steam Injection in TABER methods fall into many categories and are classified with restrictions and application conditions, thus by the analysis, researches and comparisons done in the project the best candidate and feasible method to be applied in Al-Roidhat field tends to be the Cyclic Steam Stimulation, which have a great matching with the field properties.

5.1.2 Injection of Cyclic Steam in AR-1 well of Al-Roidhat Field

The CSS is the alternating injection of steam and production of oil condensed steam from the same well or wells. The method can recover the range of (20-30) of recovery factor. It has several mechanisms such as removing accumulated asphaltic and/or paraffinic deposits resulting in an improvement of the permeability around the wellbore, decreasing the oil viscosity by increasing the reservoir temperature which in turn improves oil mobility and well productivity, increasing the thermal expansion of the oil which impacts the oil saturation and its relative permeability. In this project we have applied the CSS in AR-1 of Al-Roidhat field and the steam was injected by a wet-steam generator of 25 MMBtu/hrs of steam output, with injection rate of 252 m^3/day, steam quality of 80%, injection pressure of 1300 psi and the steam temperature is 570 F. These values were calculated and estimated by equations and figures to find the expected results that will enhance the heavy oil recovery in AR-1 in Al-Roidhat field as a sample that may explain how the field would be recoverable by the CSS method. The calculation and results have been reached in the project was based on available data we have collected from the field characteristics.

5.1.3 Results and Discussion

To determine the results of the project, firstly, we calculated the increase of the reservoir temperature by different periods (hours), steam volumes (m^3/d), radius (ft) and areas (ft^2) and the temperature of the heating zone was in the range of 450-445 F. Secondly we estimated the decrease of the oil viscosity by a correlation of oil viscosity have been made by Farouq Ali and Meldau (1983) as a function of temperature and API gravity, based in that correlation and study the cyclic steam stimulation will tend to a rapid decrease in the oil viscosity from 420 to 20.5 cp. Thirdly we calculated the incremental of the productivity index which in turn increased to 1.7 times of the normal value, then the production flow rate after the steam injected was 530 STB/day with a steam oil ratio (SOR) of 7 . Finely,we assume from the previous calculations and their positive results that the recovery factor will increase to an economic value in Al-Roidhat field after applied the CSS method.

5.2 Recommendations

1. Perform a simulation model for Al-Roidhat field to confirm the effectiveness of CSS in the field.

2. Implementation of pilot test of CSS in AR-1 well then applied for the whole field in order to achieve an incremental of the economics returns and increasing the recovery factor.

3. Perform the CSS followed by the steam flooding to enhance the efficiency of steam flooding and thus improve the recovery and production rate.

4. Study the characteristics of Al-Roidhat field, thus, study the possibility of applications of other EOR methods that may enhance the oil recovery in the field.

5.3 Limitations

1. Lack of the field data that would supply us to complete the project in a typical way.

2. The absence of soft-ware programs needed to predict the results more accurately.

3. The difficulty of finding and perform screening criteria methods to confirm the thermal EOR which should be used in the field.

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