TECHNICAL UNIVERSITY OF CRETE

Department of Mineral Resources Engineering

MSc. Petroleum Engineering

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written by

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on the subject

Investigation of the use of EOR methods in a given reservoir

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Acknowledgements

Abstract

It is widely accepted among the petroleum engineering community that Enhanced Oil Recovery (EOR) is currently one of the most active sectors of research in the oil industry. The first part of the present diploma thesis consists of a literature review where the commercially feasible Enhanced Oil Recovery methods are described. The oil recovery mechanisms each EOR method involves, the advantages, the disadvantages and some examples of successful field applications are presented. At the end of the literature review, the reader will have a good perception of the necessity of EOR implementation in the existing oil fields, the production potential of the EOR techniques and the ability to identify where and at which extent each EOR method can be applied.

The second part of the present diploma thesis investigates the implementation of Chemical EOR methods in the H1 segment of the offshore oil field named Gullfaks that is found in the Norwegian side of the North Sea. At first, a presentation of the reservoir properties is made and then a simulation study of the reservoir is conducted using ECLIPSE - 100 (2010 version) software.

Contents

Part A

Literature Review of EOR methods

Chapter 1 Introduction

1.1 Generally

From the discovery of fire to that of the atom, the development of human societies has largely been based on the conquest of energy. In all countries, energy has gradually become the most important factor of social and economic development. This disruption of the energy landscape is of particular concern as the impact of energy crises on human societies can have considerable consequences:

- Economic recession
- Rising unemployment
- International conflicts

The global population growth, the economic and technological development of the human societies have always been the driving forces of the increasing world energy demand. Since the 18th century where industrial revolution began, fossil fuels (petroleum, coal, and natural gas) became the energy sources the modern economy needed.

The beginning of the modern oil industry can be traced back in 1859 where a company with the firm *Seneca Oil Company* hired a retired railroad conductor *Edwin L. Drake* to investigate suspected oil deposits near Titusville a small village in western Pennsylvania, U.S.A. At 27th of August 1859, Drake struck oil at 69 feet (21 m) below ground using an old steam engine to drill a well that could be considered as the first large-scale commercial extraction of petroleum. The development of technology status the following years improved the drilling techniques increasing oil production to cover the global oil demand that was following the population and economical growth. Finally, oil became the dominant energy source of the 20th century and according to official forecasts, oil production will continue to increase the following years till a maximum point, the so called **peak oil.** After this point, the exact time of which is controversial, oil production will follow a continuous decline without return making the world economy to turn into other sources of energy (with the resulting geopolitical changes). Nowadays, a big part of the scientific community is investigating the use of **Enhanced Oil Recovery methods** and into what extend they are capable to delay the peak oil.

Figure 1.1: Edwin Drake, right, in 1859 with the first big mechanical oil well drilled in Titusville

1.2 The importance of crude oil in the global economy

1.2.1 Global energy demand

According to the report *International Energy Outlook 2016* (IEO 2016) that was conducted by the *U.S Energy Information Administration* the worldwide energy demand is expected to increase at an average rate of 1,4% per year from 2012 to 2040. During this period more than 50% of the projected world increase in energy demand will be the result of the **population growth** and the **economic development** of the non – OECD countries.

According to the IEO 2016 projections that are illustrated in **Figure 1.2** consumption of energy from all sources is going to increase and fossil fuels will continue to provide most of the word's energy. Most specifically in 2040 fossil fuels (petroleum, natural gas and coal) will cover 78% of the world's total energy consumption. It is also obvious that the following decades **oil will remain the largest source of energy** despite of the fact that oil's percentage share to the world's fuel mix will decrease from 33% in 2012 to 30% in 2040. [1] Moreover, according to IEA 's medium – term oil report (2016) oil demand to 2021 is for annual average increase of 1.2 m bbl/day – an annual percentage rate of 1.2%.[2]

The main factors that could possibly influence the world's energy mix are:

- Economic development of big non – OECD countries (China, India, Brazil, etc.)
- Application range of climate policies.
- Technological progress.
- Political instability / conflicts in the oil producing countries.
- OPEC production policies.
- Application range of nuclear generation.
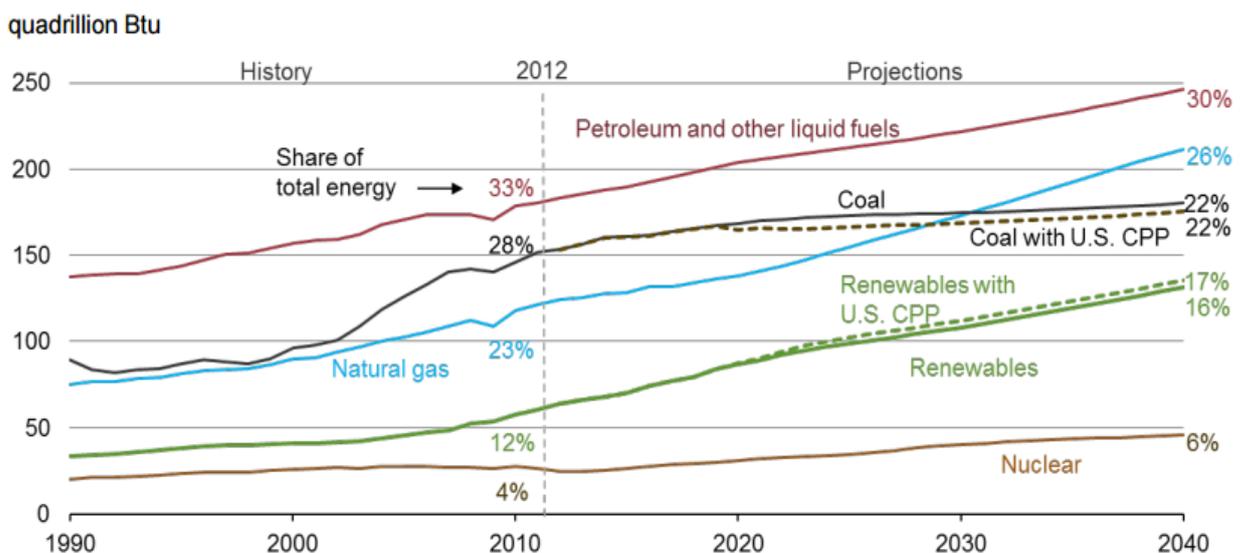
Figure 1.2: World energy consumption by energy source

1.2.2 Transportation sector

The viability of the modern civilisation relies on one key factor: The efficacy of the transportation system that must have the ability to move people, raw materials, energy, food, finished products even wastes, in a cost effective way in order to sustain the development of the global economy.

Transport sector is a basic component of the modern economy and a common tool used to promote development. In developed countries it usually accounts between 6% and 12% of the GDP and employs between 3% and 8% of the total labour force. Generally, transportation costs account between 5% and 10% of the value of a good.

What makes this sector so important is that it is **fundamental for the functionality of all the economic activities** of the modern civilisation. Relatively small changes in transportation costs, capacities or performances can have substantial impact on different economic sectors – industrial, manufacturing, agriculture and tourism among others.

The second crucial characteristic of the transportation sector is that with the existing technology its functionality relies mainly on petroleum availability. According to the IEO 2016 projections that are illustrated in **Figure 1.3** the energy consumption of the transportation sector is expected to increase at an annual average rate of 1,4% from 2012 to 2040 mainly as a result of the economic growth of the non – OECD countries. It is also obvious, that petroleum liquid products (Diesel, Jet fuel, Motor gasoline and Residual fuel oil) will remain the **dominant energy source for the transportation sector**. More specifically, the share of the petroleum liquid products in the total transportation energy demand will remain in high levels decreasing from 96% in 2012 to 88% in 2040. [1]
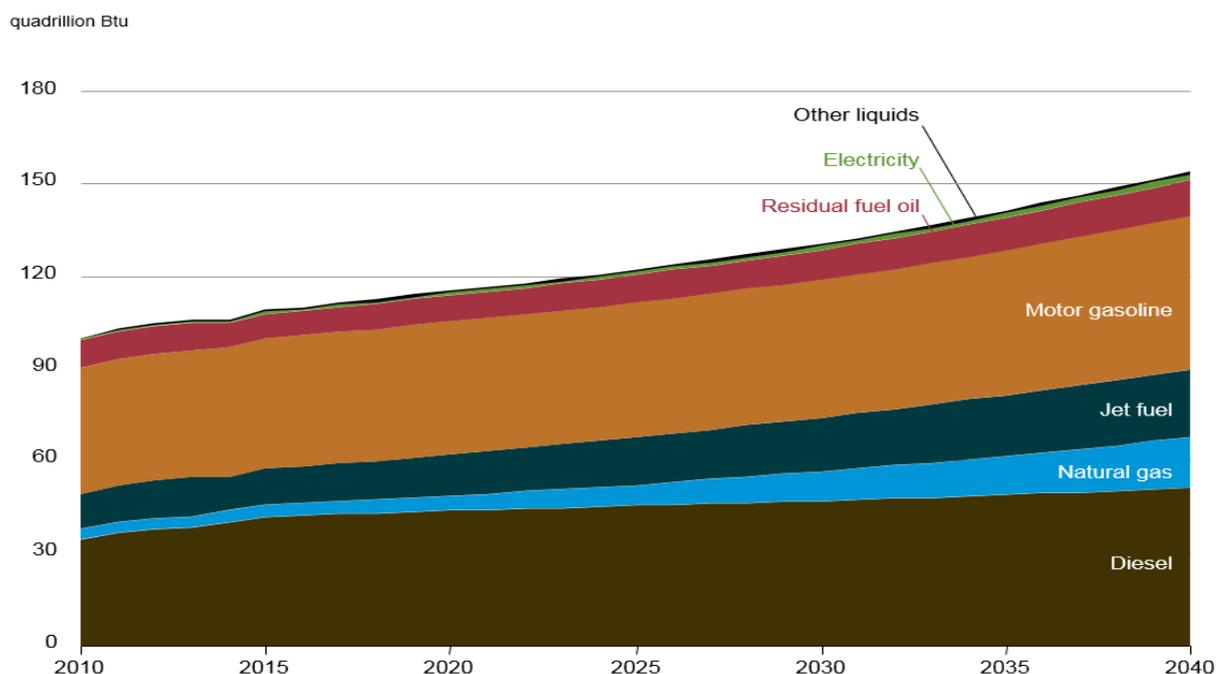
Figure1.3: World's transportation system energy consumption by energy source

1.2.3 Petrochemicals

Petrochemicals are defined as the chemicals products derived from petroleum. Petrochemical industry produces petrochemicals, through distillation of crude oil, in order to supply the manufacturing industry. There, the petrochemicals undergo several transformations and they came into useful materials that are consumed by different sectors like construction, modern healthcare, agriculture, automotive, electronics, textile and packaging among others. The petrochemical industry can be considered as one of the foundation stones of the modern economy due to its **extremely wide product range and application field.**

Petrochemicals are classified into three main categories based on their chemical structure:
- **Olefins** which include ethylene, vinyls, propylene, and butadiene
- **Aromatics** which include benzene, toluene, styrene and xylene
- **Synthesis gas** which is used to make methanol.

Generally, most refineries focus on producing transportation fuels. According to IEA 's medium – term oil report (2016), nowadays, approximately 11.5m bbl/day of oil, or 13% of the total oil demand, is used for the production of petrochemicals, of which almost 90% is used as a feedstock and the rest for thermal energy.[2]

According to the Petrochemical Market Analysis and Segment Forecasts to 2022 conducted by *Grand View Research* a market research and consulting company and published in March 2016, Global petrochemicals market is expected to witness steady growth over the next years as it is presented in **Figure 1.4**. Industries in developing countries like China, India, Thailand and Indonesia are expected to drive petrochemical products demand. [3] In accordance with the previously mentioned market analysis, IEA 's medium – term oil report (2016) estimates the oil demand for petrochemicals to increase by roughly 2m bbl/day from 2015 to 2021, an annual growth rate of almost 3%.[2]
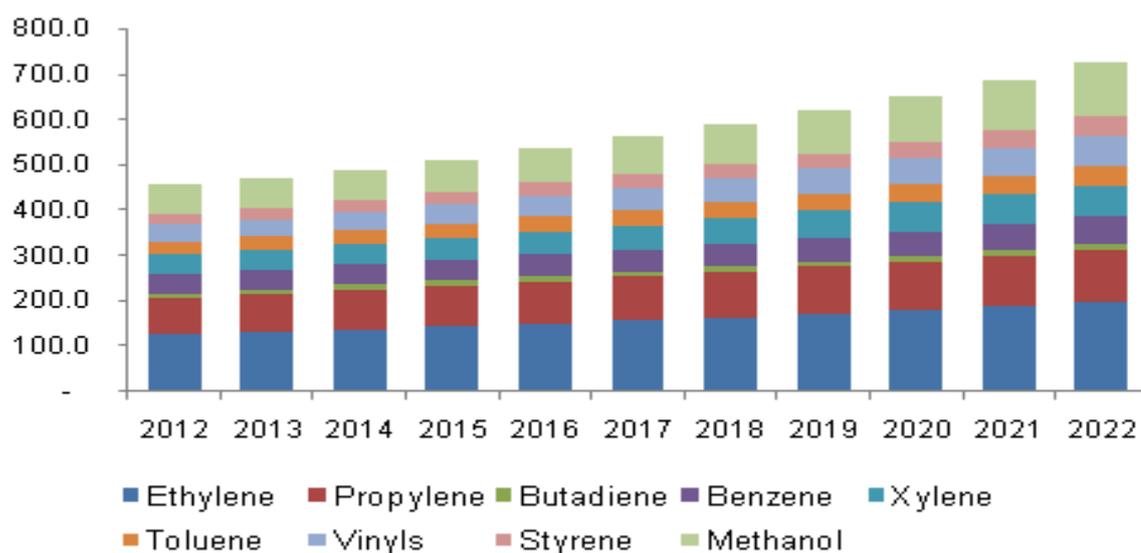
Figure1.4: Global petrochemical market volume by product, 2012 – 2022, (Million Tons)

1.2.4 Employment

The global economic impacts of oil and gas industry in terms of employment are remarkable and affect several different economical sectors. The total economic implications of the oil and gas industry could be estimated as the aggregation of the following distinguished types of impacts:

- **Direct Impacts** that consists of the jobs within the oil and natural gas industry like for example: Drilling, extraction, support services, distribution, construction of pipelines, refineries, gasoline stations.
- **Indirect Impacts** that consists of the jobs occurring throughout the supply chain of the oil and gas industry like for example: manufacturers, caterers, transportation / logistics, outsourced corporate functions.
- **Induced Impacts** that consists of the jobs related with the spending of the oil and gas labour.

According to a research that was conducted by API (2011 database) [4] and it is presented in **Table 1.1**. oil and gas industry in U.S.A. was employing directly 2.590.700 people, plus other 7.242.600 people indirectly or induced resulting totally to 9.833.300 people or equivalently 5,6% of the total USA employment. From this report it can be deduced that **for each direct job in the oil and gas industry, approximately 2.8 jobs are created in other economical sectors.**

Table1.1 : Impacts of the Oil and Gas industry on the USA employment, 2011

American Petroleum Institute	Direct Impacts	Indirect and Induced Impacts	Total Impacts	Percent of U.S.A. Total
Employment	2.590.700	7.242.600	9.833.300	5,6%

According to IEA's report, Key World Energy Statistics, 2016 [5] U.S.A. has a 13,1% share of the world oil production (2015 data), a 20,7% share of the world oil products (2014 data) and a share of 21,4% of the world natural gas production (2015 data). So, by assuming that U.S.A. has a 20% share of the global oil and gas industry, we could speculate that **globally around 13.000.000 people are employed directly by the oil and gas industry** which support other 36.400.000 jobs in other economic sectors.

1.3 Conventional Oil Reserves

Conventional oil reserves refer to the portion of oil resources that can be extracted, just after drilling, by the natural pressure of the oil in the reservoir or by pumping operations. Concerning off – shore production, an additional condition that the reserves can be drilled at a depth of no more than 5.000 ft below the sea's surface should be considered. Conventional oil reserves are those that can be extracted via primary or secondary recovery methods which both target the mobile oil of the reservoir:

- **Primary Recovery** where the natural energy of the reservoir, in the form of a displacement mechanism such as **gas drive** (gas cap or/and dissolved gas), **water drive** (active aquifer) or **gravity drainage** (high slope angle), displaces the hydrocarbons towards the well and up to surface. In primary recovery, extraction can be reinforced via **pump jacks** and other artificial lift devices. At this stage, typically a Recovery Factor between 5 to 15% is achieved.

- **Secondary Recovery** in which energy is added to the reservoir through **water flooding** or **gas injection**. The purpose of secondary recovery is to maintain reservoir pressure (if it is possible above bubble point) and to displace hydrocarbons toward the well. The successive use of primary and secondary recovery can result to a total Recovery Factor of 40 or 50%.

In **Figure 1.5** the global quantities of conventional oil that is discovered (red curve) and produced (blue curve) with the relative predictions are illustrated. It is obvious that conventional oil discoveries peaked in the early 1960s and since the mid-1980s, oil companies have been finding less conventional oil than the world has been consuming. Concerning, the world conventional oil production, it seems that it has already reached its maximum value.[6] According to EIA, conventional oil production of OPEC countries peaked in **February 2011** at 85.3 m bbl/day and that of non-OPEC countries peaked in **November 2010** at 49.8 m bbl/day. [7]
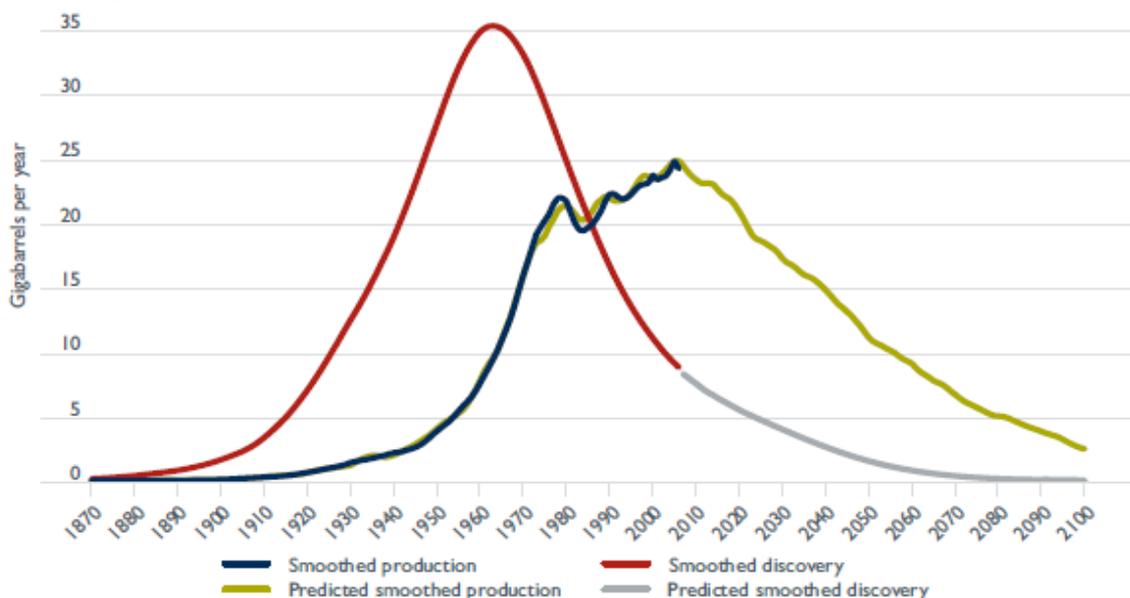
Figure1.5: Annual world discovery and production of conventional oil

1.4 Unconventional Oil Reserves

Unconventional oil reserves refer to the portion of inaccessible oil resources and to those with such a composition that cannot be recovered from an ordinary production well without being heated or diluted. For production, transportation or refinery they require specific techniques that are more complicated, more energy intensive and with higher environmental impacts when compared with the techniques used for the conventional oils. Unconventional oils or *new oils* include the following oil reserves:

- **Shale oil**
- **Tight oil**
- **Oil from Tar sands**
- **Deepwater oil**

The techniques used for the extraction of the unconventional oil reserves constitute the **Tertiary Recovery** or **Enhanced Oil Recovery** which is used to recover oil beyond secondary methods targeting the immobile oil (that oil which cannot flow towards the well due to capillary or viscous forces). The successive use of primary, secondary and tertiary recovery can result to a total Recovery Factor of 80%. Enhanced Oil Recovery methods are classified according to the oil displacement mechanism into the following categories:

- **Thermal methods** (that use heat for reduction of oil viscosity)
- **Miscible gas injection methods** (that use a solvent for miscible oil displacement)
- **Chemical methods** (that use chemicals for alteration of capillary and viscous forces)

From the illustration of the total world crude oil production **Figure 1.6**, it is obvious that due to the additional production of deep water and unconventional heavy oil, the *peak oil* is postponed and projected to occur near 2020. Another remark to be made is that the production of unconventional oil will never have the capacity to substitute the decreasing production of the conventional oil reserves. [6]
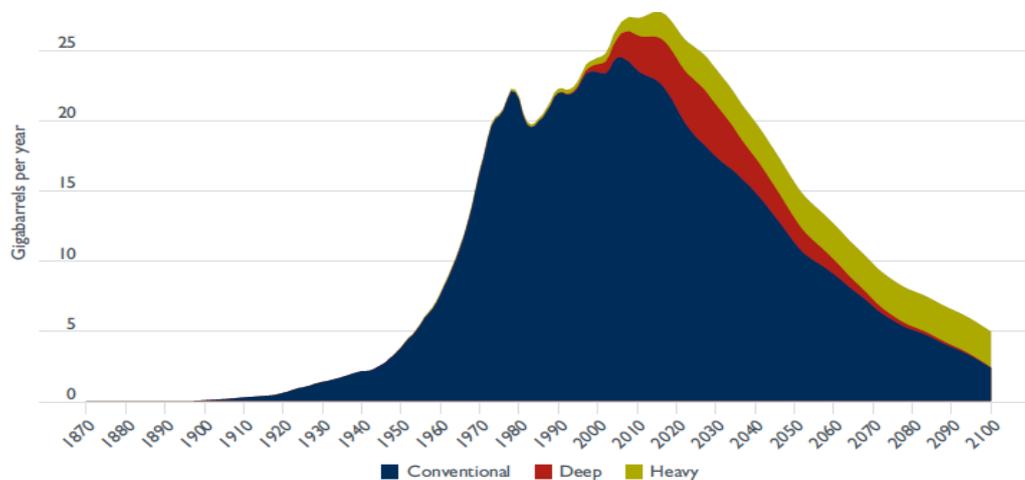
Figure1.6: Components of total world crude oil production

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1.5 EOR Methods

1.5.1 Key features of EOR methods

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The most recognizable characteristic of all EOR methods is their relative complexity of implementation when compared with the conventional methods. Therefore, the application of EOR methods in oil fields requires from oil companies to possess:

- Increased capitals to invest
- High qualified human resources
- Technologically advanced equipment
- Flexibility to the long time required for the development of EOR projects
- Ability to undertake the financial risks that the EOR projects involve due to the fluctuations in the price of oil

.   Those issues make the oil production costs of EOR methods to be substantially higher than the production costs of the conventional methods. In **Figure 1.7** that is provided by the International Energy Agency [8] it can be seen that the production cost of EOR methods cannot be less than 40 $ per barrel (2008 data). From all the above, the deduction is that the implementation and spreading of the EOR methods is entirely dependant on the price of oil and overall economics of the oil companies. Generally, the interest for implementation of EOR projects arises globally when price of oil is increasing.

Another fundamental characteristic for all EOR methods is that they have strong potential for further development as the amount of oil resources (unconventional oil) they could possibly exploit is approximately 3 times more than the quantity of oil that has already been produced, as it is seen in **Figure 1.7.**
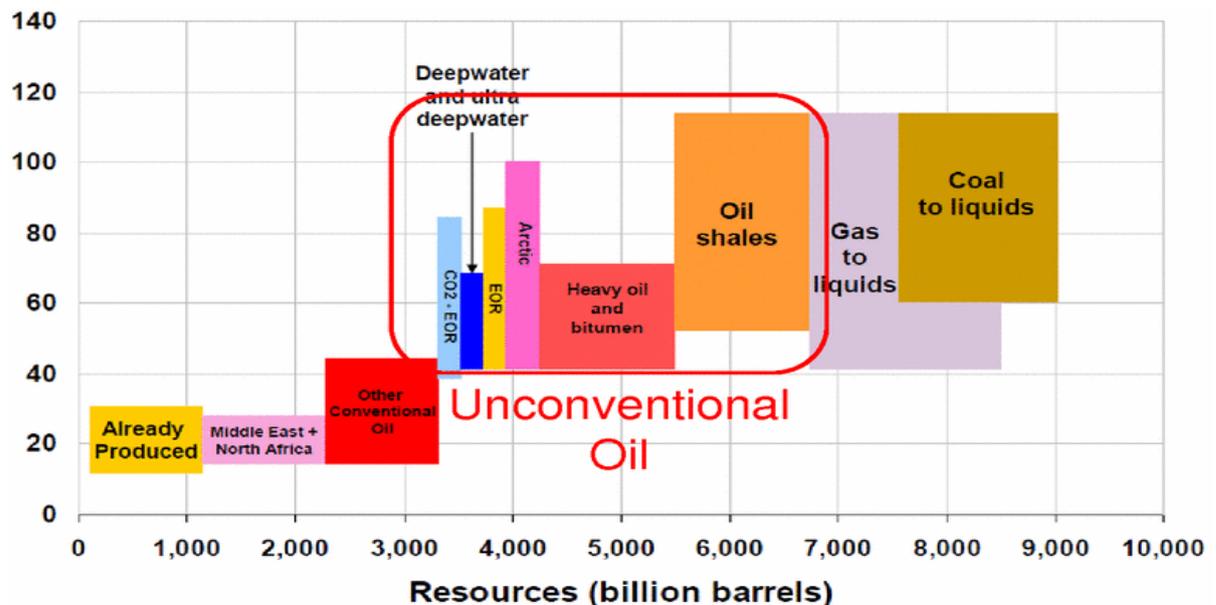
Figure1. 7: Oil production costs (US $) and resources availability

1.5.2 Current status and future trends of EOR methods

Nowadays, most of the global oil production comes from mature or maturing reservoirs forming an average worldwide Recovery Factor (from conventional - primary and secondary recovery methods) at around 35% that is considered to be relatively low. Additionally, it is has been shown already, the new oil field discoveries have been declining steadily during the last decades. For these reasons, the last years, oil companies have been directed towards developing further the EOR technologies in order to increase their effectiveness and subsequently the obtainable recovery factors of the existing oil reservoirs.

According to the article *Enhanced oil recovery challenges & opportunities* that was published by the *World Petroleum Council* [9] around 3,5 % of the global daily oil production (2010 data) was provided by Enhanced Oil Recovery methods (3 million barrels of daily production out of the total ~ 85 million). From the histogram in **Figure 1.8** it is obvious that the majority of the EOR oil production relies on the thermal projects.

It is widely accepted that as time goes by and conventional oil resources are depleting, the global oil production will rely more and more on the EOR methods. The implementation of EOR methods will be developed through the following parallel approaches:

- **Life – cycle planning** for the existing, aging conventional oil reservoirs, targeting the optimisation of the overall oil recovery (long term profits) and not the immediate oil recovery. Better resource exploitation can be achieved through sustainable oil field development and final implementation of the EOR methods.

- Exploitation of the **unconventional resources** like oil shales or tar sands where conventional methods cannot be performed.

- Further development of the EOR techniques in order to apply them at the **offshore fields.**
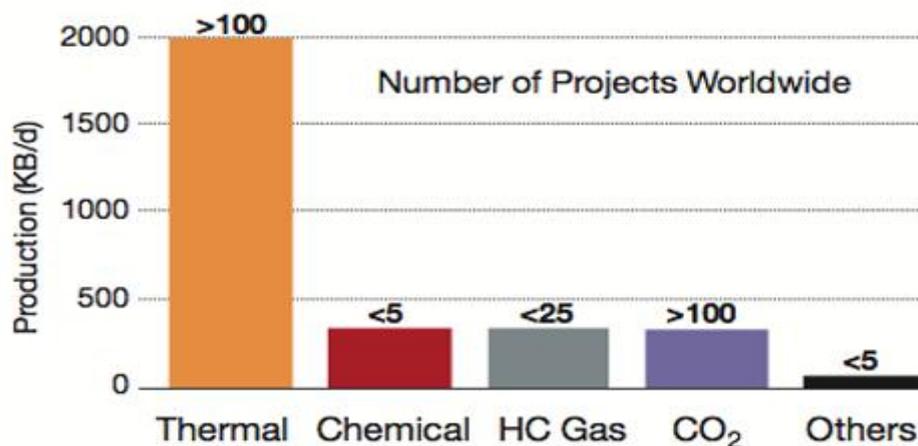
Figure 1. 8: Worldwide EOR productions rates

1.6 Appendix

Primary energy is the energy that is embodied in resources as they exist in nature: chemical energy embodied in fossil fuels (coal, oil, and natural gas) or biomass, the potential kinetic energy of water drawn from a reservoir, the electromagnetic energy of solar radiation, and the energy released in nuclear reactions. For the most part, primary energy is not used directly but is first converted and transformed into secondary energy such as electricity and fuels such as gasoline, jet fuel, or heating oil which serve as energy carriers for subsequent energy conversions or market transactions.

Final energy ("delivered" energy) is the energy transported and distributed to the point of retail for delivery to final users (firms, individuals, or institutions). Examples include gasoline at the service station, electricity at the socket, or fuel wood in the barn. Final energy is generally exchanged in formal monetary market transactions, where also typically energy taxes are levied. An exception are so-called non-commercial fuels – i.e., fuels collected by energy end-users themselves such as fuel wood or animal wastes, which constitute important energy sources for the poor countries.

IEA (International Energy Agency) is an organisation that established in November 1974 to promote energy security and provide authoritative energy analysis for its member countries.

TOE (tonnes of oil equivalent) is a unit of energy defined as the amount of energy released by burning one tonne of crude oil. One TOE is approximately 42 Gigajoules.

OPEC (Organization of the Petroleum Exporting Countries) is an intergovernmental organization of 14 nations, founded in 1960 in Baghdad. As of 2015, the 14 countries accounted for an estimated 43 % of global oil production and 73 % of the world's "proven" oil reserves, giving OPEC a major influence on global oil prices.

Peak oil is the point in time when the maximum production rate of petroleum is reached, after which, it is expected to enter terminal decline.

Btu (British thermal unit) is a standard unit of energy that is used in the United States and sometimes in the U.K. It represents the amount of thermal energy necessary to raise the temperature of one pound of pure liquid water by one degree Fahrenheit at the temperature at which water has its greatest density (39 degrees Fahrenheit). One Btu is equivalent to approximately 1055 joules.

OECD (Organization for Economic Cooperation and Development is a unique forum where the governments of 34 democracies with market economies work with each other to promote economic growth, prosperity, and sustainable development. Today, OECD member countries account for 63% of world GDP, 75% of world trade, 95% of world official development assistance, over 50% the world's energy consumption, and 18% of the world's population.

GDP (Gross Domestic Product) is the monetary value of all the finished goods and services produced within a country's borders in a specific time period.

1.7 References

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Chapter 2 Unconventional Oil Reserves

2.1 Oil from Oil Sands

2.1.1 Oil sands definition

Oil sands (that are sometimes referred as tar sands or bituminous sands) are sediments that can be distinguished in two types:

- **Water wet** oil sands which are composed of solids (quartz sand, clays and minerals ~85%), water (~5%), and an organic matter that is called bitumen (~10%). Each grain of sand (62,5 to 250 μm) is covered by a film of water, that contains tiny mineral particles - the fines and which is surrounded by another film of bitumen as it is shown in **Figure 2.1.**

- **Oil wet** oil sands which are composed of solids (quartz sand, clays and minerals ~90%) and bitumen (~10%). Sediments of oil wet sands are found in Venezuela and Utah among other areas.
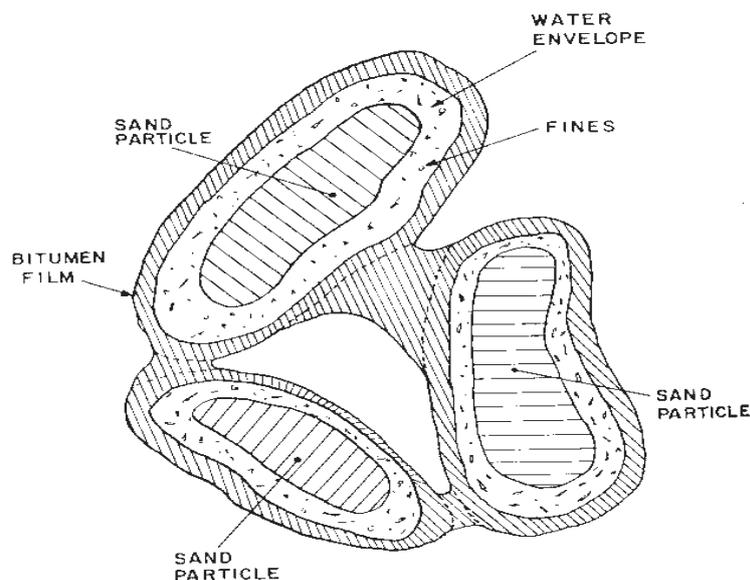
Figure 2.1: Water wet oil sands

The grains (62,5 to 250 μm) that form the oil sands are bonded in a triangular shape and generally they are very abrasive. The space that is created by this triangular shape is filled by other materials like rocks, clay particles, water or natural gas. The absolute permeability that is resulted is high although the bitumen remains immobile due to its high viscosity. The porosity of the oil sand formation is relative high varying between 25% and 35%. The world largest deposit of oil sands is located in Alberta, Canada (water wet oil sands).

Bitumen is a sticky, black and highly viscous liquid which remains immobile under conditions existing naturally within the earth. It is the heaviest form of all kinds of petroleum with °API ranking between 8° and 14°. The bitumen content in oil sands ranges between 1% and 18%. Oil sands which contain less than 6% bitumen are considered poor sediments and usually are not exploited. Bitumen must undergo oil upgrading to form synthetic crude oil before being accepted by the refineries. Generally, it takes nearly two tons of oil sands to produce one barrel of synthetic crude oil. The chemical composition of the bitumen depends on the initial oil that comes from, the migration procedure and the create conditions of the tar sand formation. In general, bitumen is relatively rich in NSO compounds and poor in Hydrogen when compared to the rest of hydrocarbons. A typical bitumen's composition (sample taken from Alberta Oil Sands, Canada) is presented in **Table 2.1** [1]

Table2.1: Typical bitumen's elemental analysis

Bitumen Alberta's Tar Sands	Content
Carbon	83,2 %
Hydrogen	10,4 %
Sulfur	4,8 %
Oxygen	0,94 %
Nitrogen	0,36 %

2.1.2   Formation of oil sand accumulations

The bitumen that is contained in the tar sands has its origin to the conventional oil. In fact, it is about conventional oil that has migrated from the source rock and has undergone processes of evaporation of the light components, biodegradation, dissolution in groundwater and oxidation, resulting in changes in the chemical composition and in the physical properties.

An example is illustrated in **Figure 2.2** that refers to the Athabasca oil sand formation in Alberta, Canada. First of all we can see that Athabasca oil sand formation is located near the sea level. This is because incised valleys were formed by fluvial processes separating the Paleozoic limestones from the Mesozoic calcareous shales. Subsequently, the valleys were filled with successive layers of fluvial deposits and marginal – marine sediments (the last ones because of an early Cretaceous sea-level rise) which formed Athabasca host sands. Concerning the oil generation and migration it is believed that occur during the late Cretaceous, which is contemporaneous with the deposition of the last host sands. The tectonic load resulting from the development of the Rocky Mountains in the pre-Cretaceous period buried the nearby basin to become a source rock. The oil that generated, migrated following the path the black arrows indicate in order to end in a structural and stratigraphic trap where due to biological activity became biodegraded forming the oil sands. [2]
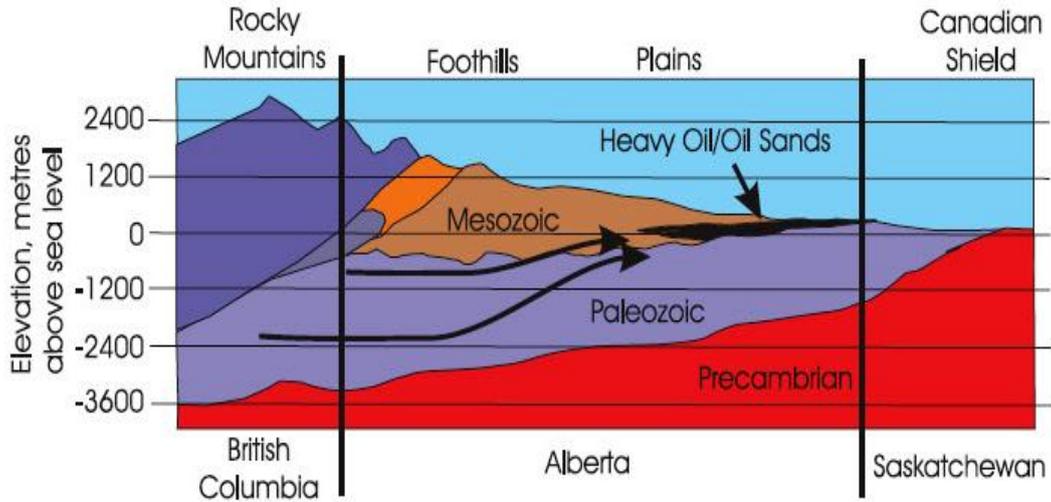
Figure 2.2: Geological cross section of Alberta oil sand region

2.1.3 Global oil sand reserves

The biggest oil sand deposits in the world are located in Canada and in Russia. According to the International Energy Agency that has assuming 10% Recovery Factor of the total oil in place the World's recoverable oil is estimated to be $354 * 10^9$ bbl (May 2014) the global distribution of which is presented in **Table 2.2** [3]

Table2.2: Technically recoverable oil from tar sands

Geographical Area	Technically recoverable oil from tar sands (10^9 bbl)
World	354
Canada	265,5
Russia	76,2
USA	4,3
Africa	4
Central Asia	2
China	1
South America	0,9
East Europe	0,1

2.1.4 Production techniques

The method used to extract bitumen from tar sands depends upon the depth in which the deposits are buried. Generally, if the tar sands are buried in a depth less than 75 m then surface mining is used and approximately 20% of the total tar sands reserves are recoverable via this method. Otherwise, which means for the rest 80% of the tar sands reserves, bitumen is recovered via in – situ production. Both of the techniques can be characterized as energy-intensive, expensive and with significant environmental impacts.

Surface mining (or open-pit mining) which includes the following procedures:

1. Shallow excavation for the removal of the top layers of soil.
2. Mining of the exposed tar sands.
3. On-site processing that aims the separation of the tar sands mixture into its three components: sand, water and bitumen. This segregation is achieved by mixing the tar sands with amounts of hot water into a separation vessel where the quantities of bitumen result to float on the surface. The water is recycled for a future processing and the sand is driven to large storage areas called tailing ponds
4. On-site processing that aims the decrease of the bitumen's viscosity using diluents like natural gas or crude oil in order to make the bitumen able to be transferred via pipelines to an upgrading facility.

In – situ production which requires the drilling of wells to extract the bitumen and includes the following procedures:

1. Reduction of the bitumen's viscosity so that it can flow by increasing the formation's temperature or by injection of chemicals.
2. Recovering of the liquefied bitumen from the buried formation up to the earth.

Concerning in – situ production techniques, it depends whether the tar sands are water wet or oil wet. If they are water wet, the connate water enhances the use of water – based methods to separate the bitumen from the solids. In the case of oil – wet tar sands a method based on solvents and chemicals must be used. Nowadays, two in - situ methods are commercially available and address to water wet tar sands:

1. **Steam Assisted Gravity Drainage** (SAGD) which is the most widely used. In this method a pair of horizontal wells one slightly higher than the other is drilled through the tar sand formation. Steam is injected into the upper well, where the increased pressure and temperature make quantities of bitumen to flow downward with the assistance of the gravity to the second horizontal well, where it is pumped to the surface.
2. **Cyclic Steam Stimulation** (CSS) where two vertical wells are used. One injection well from which steam is injected in the tar sand formation to liquefy the bitumen and one production well towards which the bitumen is flowing.
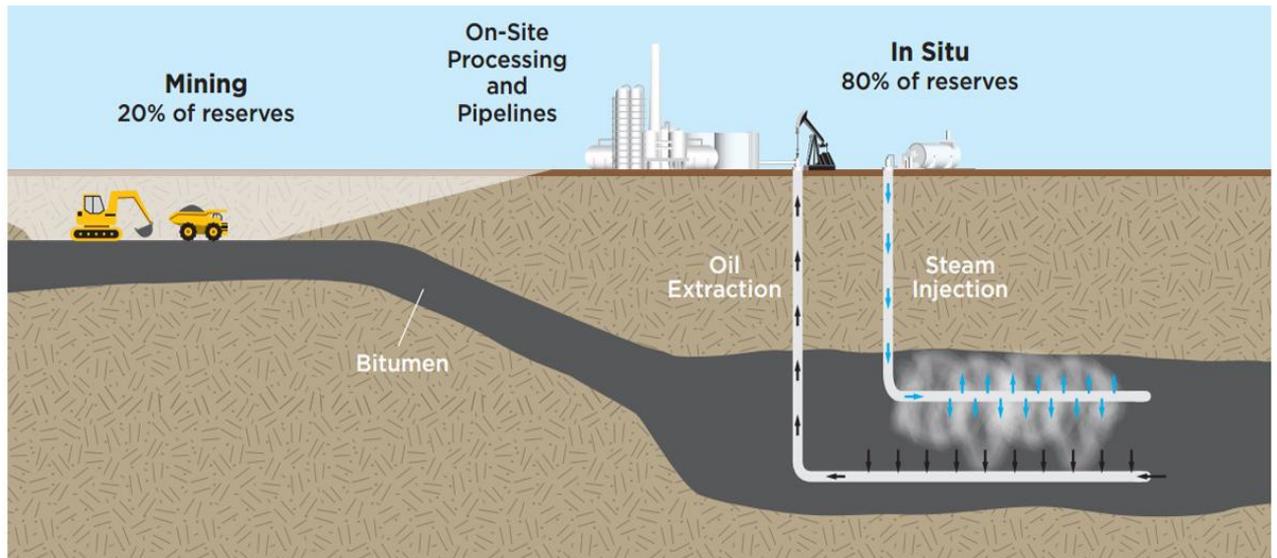
Figure 2.3: Extraction techniques for Tar Sands

2.1.5   Environmental impacts

Air quality impacts

Lifecycle Green House Gases emission intensity makes tar sand exploitation the most air polluting process to produce oil. The average emissions of Green House Gases resulting from bitumen extraction and upgrading to synthetic crude oil is estimated to be 3,2 to 4,5 times greater per barrel than for conventional crude oil. When comparing surface mining and in - situ methods, it can be deducted that in - situ methods have much bigger environmental impacts, as they require larger amounts of energy for the production of a given quantity of crude oil. In fact, by lifecycle analysis, it has been shown that in situ – methods produce on average 2,5 times more Green House Gases than surface mining.[4]

Water & Land quality impacts

From the other hand, in situ production methods cause significant smaller surface disturbance and have smaller requirements for process water. More specifically, in – situ methods require approximately 0.9 barrels of water per barrel of synthetic oil whereas mining method requires between 2 and 4 barrels of water after taking into account water recycling. Moreover, when extracting by the mining method the water that is used becomes toxic as it gets contaminated with naphthenic acids, un - recovered hydrocarbons and trace metals and must be retained in tailings ponds. These tailing ponds cover huge areas with no or little possibility to be reclaimed and with a remaining likelihood for groundwater system contamination. [5]

Nowadays, the majority of bitumen production is done by surface mining but as time goes by and tar sands reserves are located in less easily accessible reservoirs, the number of in – situ applications are anticipated to increase significantly. The development of more efficient and more environmentally friendly technology in this specific area becomes essential.

2.2 Shale Oil

2.2.1 Oil Shales definition

Oil shale is a fine-grained sedimentary rock containing relatively large amounts of organic mater. The organic matter is intimately bounded within the mineral matter (shale), which usually consists of fine grained silicate and carbonate minerals. Around 80 to 99% of the organic matter in oil shales is found in the form of kerogen and the rest is in the form of bitumen which is dispersed in the kerogen network. Oil shale does not contain any free oil and this must be produced by a process that is called pyrolysis or retorting in which the kerogen is thermally decomposed to produce the shale oil. For commercial grades of oil shale the content in kerogen should be at least at 5% wt.

Generally, oil shales exhibit a wide range of mineral content, chemical composition, age, type of kerogen, and depositional history. Nowadays, the most practical way to classify the many types of oil sale is by using as a discriminatory criterion their environment of deposition. This scheme of classification reflects the differences in the chemical composition of the organic matter and subsequently useful estimations about the possible yield and the composition of the produced oil can be extracted. According to the depositional environment we can distinguish:

- **Terrestrial** oil shale the organic matter of which is derived from the residues of terrestrial vascular plants that were deposited in stagnant, oxygen-depleted waters on land such as **swamps and bogs**. Terrestrial oil shale deposits usually are small in size, but they can be of a very high grade.

- **Lacustrine** oil shale the organic matter of which is derived from algae or bacteria that lived in freshwater, brackish, or saline **lakes**. Residues of terrestrial vascular plants can also have a contribution. The size and the grade of lacustrine oil shale deposits is varying.

- **Marine** oil shale the organic matter of which is derived from marine algae and several marine micro organisms. Most of the marine oil shales are located in **sea shores** where anoxic zones and up welling currents are enhanced.

Within this classification scheme, six different types of oil shales are identified as it is presented in **Table 2.3.** The largest deposits of oil shales worldwide are Marinites and Lamosites. [6]

Table 2.3: Classification of oil shales

Terrestrial Oil shales	Lacustrine Oil shales	Marine Oil shales
Cannel coal	Lamosite Torbanite	Kukersite Tasmanite Marinite

2.2.2 Kerogen

Kerogen could be defined as the portion of the organic matter found in sedimentary rocks that is insoluble in the organic solvents. In fact what makes kerogen insoluble is its high molecular weight and molecular complexity. Kerogen constitutes the most abundant form of organic carbon on earth (1000 times more abundant than coal and petroleum in reservoirs). As it is a mixture of organic material there is not a specific chemical formula and kerogen's chemical composition, quality and properties will differ among different oil shale samples. Based on kerogen's elemental composition 4 different types can be distinguished as it is presented in **Table 2.4.**

Table 2.4: Classification of kerogen

	Type I	Type II	Type III	Type IV
Source material	Lacustrine	Marine	Terrestrial	Terrestrial
H/C	>1,5	1-1,5	0,7-1	<0,7
O/C	<0,15	0,03 – 0,18	0,03 – 0,3	<0,5
Products	Oil + Gas	Oil + Gas	Gas	-

Kerogen Type I is the most rare and most qualitative type of kerogen as it has the largest H/C ratio which subsequently makes it the most capable to generate Hydrocarbons (mostly liquid). Less than 3% of the word's oil and gas reserves come from kerogen Type I. It is formed mostly from lipid rich biomass deposited in stratified lakes. **Kerogen Type II** is the most abundant type of kerogen. It is formed in a variety of environments but generally it consists of marine source material (zooplankton, phytoplankton and bacterial remains). Kerogen Type II has lower oil generating potential and higher organic sulphur levels than kerogen Type I. **Kerogen Type III** exhibits very low oil generating potentials but from the other hand the gas – generating potentials are very high. It is derived from woody terrestrial material. **Kerogen Type IV** has no potential or little potential to produce gas hydrocarbons. It consists mostly from terrestrial and decomposed – oxidised organic material. **Oil shales are compromised from kerogen Type I & II.**

Kerogen is so widely dispersed through the oil shale that huge volumes of rock must be processed to obtain moderate amounts of shale oil**.** Even the richest oil shale yields only about **three barrels of shale oil per ton of oil shale processed**. In order to evaluate the quality of oil shale the weight percent of organic carbon is used (TOC). Generally, 0,5% TOC is considered the minimum for an effective source rock, whereas for potential exploitation of oil shales at least 5% TOC is required. In Table 2.5 the oil shales are classified according to their concentration of organic material.

Table 2.5: Total Organic Carbon in Oil Shales

Total Organic Carbon Weight %	Oil Shale Quality
<0,5	Very Poor
0,5 to 1	Poor
1 to 2	Fair
2 to 4	Good
4 to 12	Very Good
>12	Excellent

2.2.3 Formation of oil shales

Oil shale sediments depending on the depth of their burial they are subjected in geothermal heating (usually 25 ºC to 30 ºC for every Km) and pressure which are responsible (along with the parameter of time) for the thermal maturity of the organic matter. When oil shale sediments are exposed for the appropriate time to high enough temperature, kerogen is going through the transformation stage of katagenesis and is decomposed to form oil and gas. In such circumstances the oil shale sediments are becoming **source rocks** and the hydrocarbons that are generated remain in their small porosity – permeability formations or in some occasions they can migrate to other formations (reservoirs).

On the other hand, when oil shale sediments remain in relative shallow depths and are not exposed in increased temperatures then the process of katagenesis cannot occur and the organic matter remains thermally immature. In this case where kerogen is not converted to hydrocarbons, shale sediments are likely to have economic potential for shale oil production. As **Figure 2.4** illustrates, for kerogen to be preserved or in other words, for the organic matter to remain immature, oil shales should be buried in depths, less than 1,5 km. As the depth of burial is increasing, kerogen is being converted to hydrocarbons (oil window and gas window successively).
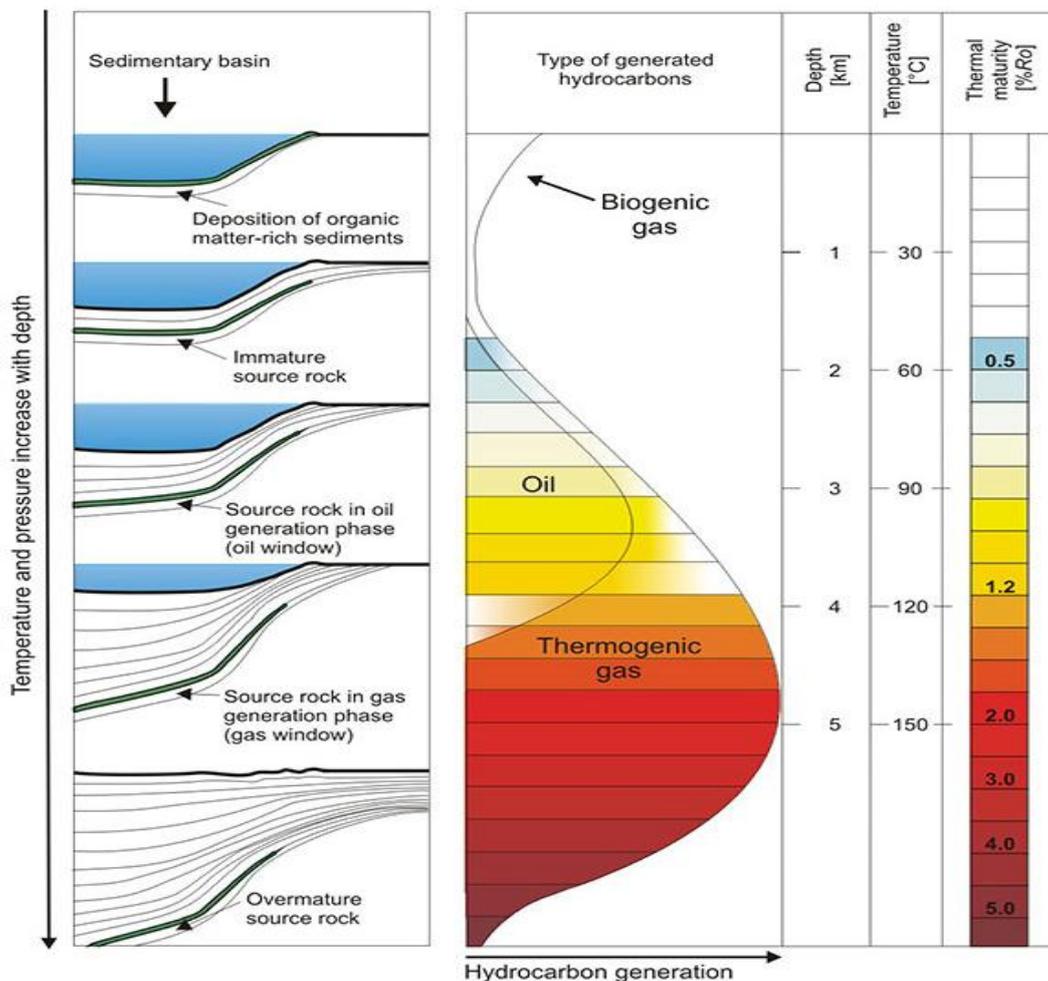
Figure 2.4: Hydrocarbon generating phases versus increasing burial depth and temperature

2.2.4 Global shale oil reserves

Generally, oil shale deposits are distributed widely throughout the world differentiating from crude oil deposits which are more concentrated in certain regions of the world. Altogether, little is known about many of the world's deposits of oil shale and much exploratory drilling and analytical work need to be done. For example, many prospective shale formations should exist at the areas of the large oil fields in the Middle East or in the Caspian region. Nowadays, the largest known oil shale deposit is found in the Green River Formation in the western United States.

According a report that was prepared by the U.S. Energy Information Administration (2013 data) that included 41 countries, 95 basins and 137 formations, the technically recoverable world shale oil resources are estimated to be 335 billion barrels (ARI estimates have 10 billions barrels divergence from EIA because the last one consider 10 billions more from USA tight oil resources means 345 in total). In **Table 2.6** the distribution of the world shale oil resources is presented whereas **Figure 2.5** illustrates the locations of the world shale resources (oil shales along with gas shales). [7]

Table2. 6: Technically Recoverable World Shale Oil Resources

Geographical Area	Technically Recoverable Shale Oil Resources (10^9 bbl)	Risked Shale Oil In – Place (10^9 bbl)
World	334,6	6753
Russia	74,6	1243
USA	47,7	954
China	32,2	644
Argentina	27	480
Libya	26,1	613
Australia	17,5	403
Venezuela	13,4	269
Mexico	13,1	275
Pakistan	9,1	227
Canada	8,8	162
Others	65,1	1483
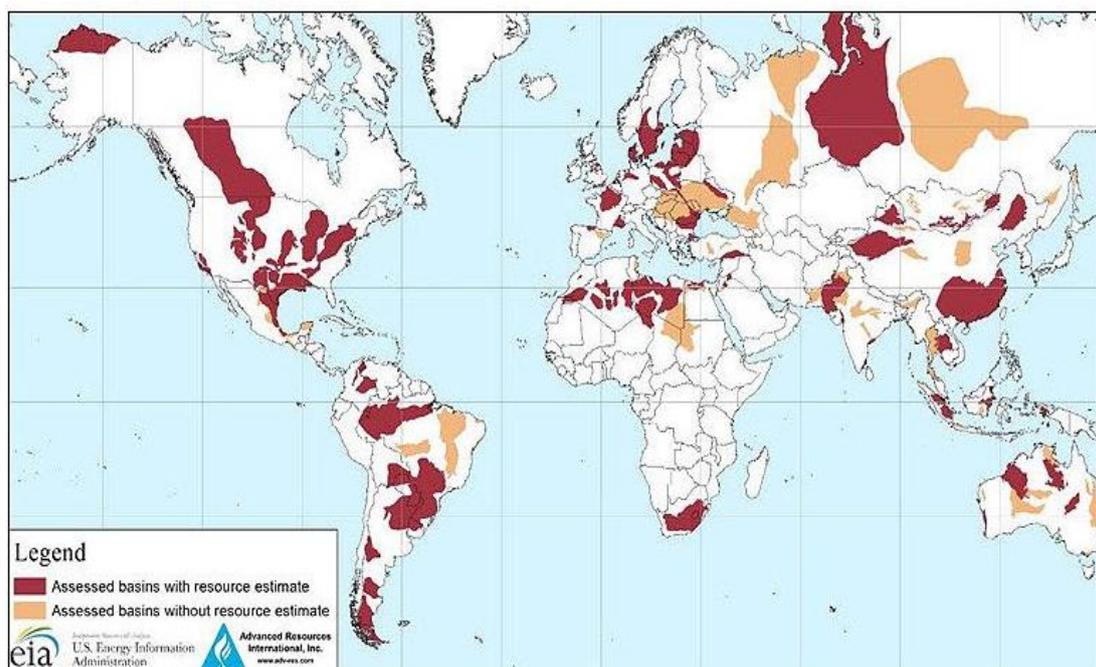
Figure 2.5: Location of world shale resources

2.2.5 Production techniques

The only way to extract shale oil from the oil sale deposits is through thermal decomposition of the contained kerogen quantities. Thermal decomposition of the macromolecular kerogen material to smaller hydrocarbon molecules is possible if it is exposed to temperatures around 500 ℃ or higher in an anoxic environment. The techniques for shale oil production can be distinguished in two main categories:

A. **Ex situ production** where the thermal processing of the oil shale deposits takes place aboveground, at surface facilities. It involves the following procedures:

1. Mining (surface or underground) of oil shale deposits.

2. Grinding of oil shale rocks to the desirable particle size.

3. Retorting (pyrolysis) of oil shale particles to produce shale oil (kerogen oil).

4. Upgrading of shale oil to produce synthetic crude oil.

5. Disposal of the inert inorganic material (around 80% of the mined material)

B. **In situ production** where the thermal processing of the oil shale deposits takes place at their natural deposition setting. It involves the following procedures:

1. Fracturing the deposit to increase the permeability of the oil shale formation

2. Retorting through underground combustion or by injecting heated gases / liquids

3. Recovering the liquid and gaseous hydrocarbons through the production wells

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Generally, through **ex situ production** of shale oil, high Recovery Factors can be achieved ranging between 70% and 90% of the total organic content in the oil shale formation. Also, there is a better control of the procedures involved and the operating variables when compared with in situ production. From the other hand, ex situ production exhibits higher operational costs than in situ production and requires higher capital investments for larger plant facilities. For ex situ production there are two available mining techniques that are used depending on the depth of the oil shale deposit:

- **Surface (open pit) mining** that is preferred when the oil shale formations are buried in shallow depths. Generally, this mining method is economical viable when the ratio of overburden thickness to oil shale formation thickness is less than 1:1. One main drawback of this method is the need for reclamation of the mined land. An example of such an application is Permian Iratí Formation in Brasil.

- **Underground (room and pillar) mining** as it is illustrated in **Figure 2.6** is preferred when the oil shale formations are buried deeper making surface mining not economical viable. This method is more costly than open pit mining as it requires supporting structures to prevent collapse, ventilation system, emergency exits. From the other hand, exhibits significant advantages as it has minimum surface disturbance (noise, dust, land occupation) and the operations cannot be disturbed by the weather conditions. It has been successfully used in Green River Formation in U.S.A. and in formations in north-eastern Estonia.

Concerning the procedure of surface retorting (pyrolysis) several configurations have been developed and tested in pilot scale but few of them proved to be efficient enough to operate long term for commercial production. It has been proved that different pyrolysis techniques result in different shale oil properties and shale oil yields. The pyrolysis conditions of the shale oil particles can differentiate by the way the required heat energy is produced, trasfered or recycled. The retorting technologies that have been used successfully and are mature enough for commercial production are presented at **Table 2.7** [8]

Table 2.7: Comparison of world oil shale commercial retorting technologies

Retorting Technology	**Fushun**	**Kiviter**	**Galoter**	**Petrosix**	**Alberta Taciuk**
Country	China	Estonia	Estonia	Brazil	Australia
Daily Oil Shale Feed Capacity (Tones)	100 - 200	1000	3000	1600	6000
Oil Shale Particle Size (mm)	10 - 75	10 - 125	0 - 25	6 - 50	0 - 25
Oil Yield (% of Fischer Assay)	65	75 - 80	85 - 90	90	85 -90
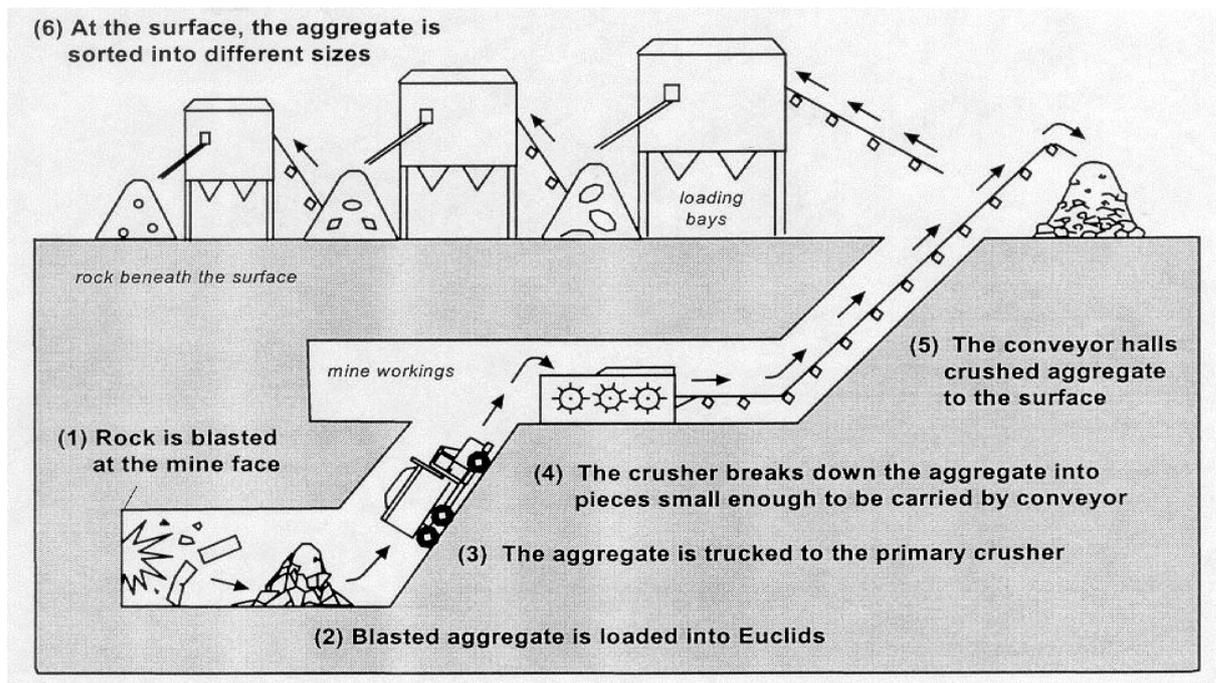
Figure 2.6: Underground (room and pillar) mining

   In situ production offers the potential for economically viable exploitation of oil shale formations that are difficult or impossible to be exploited by mining techniques. Such formations identical for in situ production could be deeply buried or very thick or of low grade. The amount of oil shale reserves than in situ production is referring to, is remarkable as almost half of the oil shale deposits can be characterized as of low grade meaning that less than 10 gallons of shale oil can be produced per ton of oil shale processed. Just to have an order of magnitude, there are oil shale formations from which 35 gallons of shale oil per ton of oil shale ore, can be yielded. Also, in situ production techniques tend to be more economical as they do not involve the processing of the large quantities of inert inorganic material (mining, transportation, grinding and disposal). From the other hand, it has been proved that in situ production techniques result to lower shale oil yields (lower Recovery Factors) if compared to ex situ production techniques when equal amounts of oil shale of equivalent grade are processed. In **Table 2.8** the in situ losses of organic matter are illustrated for every method making clear that through ex situ methods lower in situ losses (means higher Recovery Factrors) are achieved. However, the shale oil produced from in situ methods tends to be of higher quality (the kerogen macromolecules are cracked more efficiently) than the shale oil produced in above ground retorts. Also when referring to the drawbacks of in situ production methods, the potential of aquifer contamination should be mentioned. Finally, a significant disadvantage of the in situ recovering methods is the great duration of time that it is required for the underground heating – retorting of the shale oil bed (some months or years). In situ production methods can be divided in the following two subcategories:

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The true in situ method in which there is minimal or no disturbance of the ore bed and involves the following procedures:

1. Drilling / Fracturing of the shale oil formation

2. Underground retorting (through injection of heated gases / liquids or through electrical heating)

3. Recovering the shale oil and the hydrocarbon gases via production wells

The modified in situ method which can be considered as a combination of mining and in situ method and involves the following procedures:

1. Subsurface mining to create a void and surface retorting of the mined shale

2. Blasting the oil shale bed so particles are formed (rubble like texture)

3. Underground retorting of the rubberised oil shale formation

4. Recovering the shale oil and the hydrocarbon gases through production wells

More analytically, the first step of the modified in situ method is to remove an upper portion of the oil shale bed (approximately 20% of the total oil shale bed volume) by mining techniques so as to create the desired void volume. This portion of oil shales is treated via surface retorting methods. The second step is to blast the oil shale bed adjacent to the void portion in order to rubberise it. The third step includes the ignition of the upper part of the oil shale deposit. The basic principle of the method is to burn a part of the organic matter of the oil shales in order to pyrolyse and recover the remaining hydrocarbons. As the burning front is descending through the rubble bed (at a rate of several meters per week) the underground retorting of the oil shale formation is achieved. The shale oil that is produced ahead of the combustion front flows to the bottom of the rubble bed and is pumped to the surface via the production wells. In **Figure 2.7** the stages of the modified in situ method (vertical retorting) are illustrated. Following the same principles we can also have horizontal retorting of the modified in situ method.
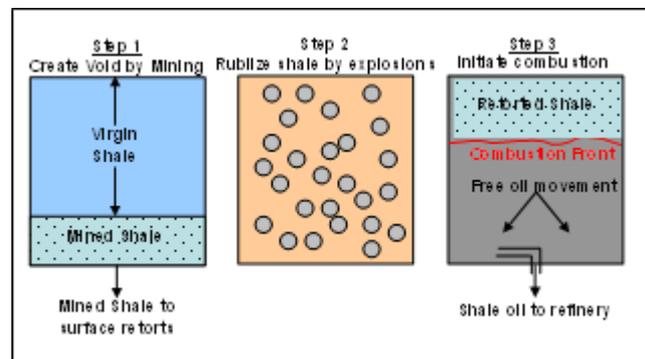

Figure 2.7: The stages of the modified in situ method

Generally, oil shales are formations of low permeability and porosity a characteristic which results in reduced heat transfer coefficient in the oil shale deposit hindering the retorting (pyrolysis) to take place and reducing the easiness of the inflow of air and outflow of produced shale oil and gases. The modified in situ retorting method that includes blasting – rubberising the oil shale formation demonstrates increased overall recovery factor, when compared with the true in site method, as it manages to expose more of the target deposit to the heat source and to facilitate the flow of the produced hydrocarbons towards the production wells.

Table 2.8: Comparison of oil shale production techniques

	Ex situ methods		In situ methods	
	Open pit Mining	Underground Mining	Modified in site	True in site
In situ losses [9]	Very low	15 – 20%	30 - 40%	50%
Production cost $/Bbl (2004) [10]	43$	52$	57$	35$

2.2.6 Environmental impacts

Air quality impacts

Shale oil production affects air quality through the generation of fugitive dust and emissions of acidic and greenhouse gases. When compared with the rest unconventional oil sources the air quality impact of shale oil production can be characterised as moderate and manageable. The production of airborne dust particles is attributed mostly to operations like blasting the oil shale formations, oil shale surface mining, grinding (sizing) the oil shale rocks and transporting oil shale rocks via trucks. Dust particles emissions constitute a very important issue for the health and security of the miners, especially in underground operations where facilities for ventilation and filtration of the air are required. The environmental impact of the open – pit mining depends on the size of the dust particles that are formed, the humidity of the air and the intensity of the prevailing winds.

The retorting (pyrolysis) process includes heating the oil shale particles at a temperature near 500 °C for most of the cases (there are some reactors that use higher temperatures) in the absence of oxygen. During the anoxic reaction of pyrolysis the macromolecular organic matter (kerogen) of the oil shale particles is decomposed to chemical compounds of small molecular weight. These chemical compounds initially, when they are formed they are in gaseous state and the kerogen oil or shale oil is formed via condensation of the gaseous pyrolysis products. The lighter part of the gaseous pyrolysis products cannot condensate and constitute the pyrolysis by products. Those small molecular gases are carbon monoxide (CO), carbon dioxide (CO_2), hydrogen sulphide (H_2S) and small molecular hydrocarbons like (CH_4, C_2H_6, C_2H_4, C_3H_8) among

others. The production of these by products can be reduced to an extent with the appropriate adjustment of the pyrolysis reactor – process.

The combustion of oil shale either during in situ retorting for shale oil formation or in combustors of electricity generation plants (Estonia) results in gaseous emissions. Among others there is production of carbon monoxide (CO), carbon dioxide (CO_2), ammonia (NH_3), dust particles and trace metals species as mercury. Also, the nitrogen and sulphur content of the kerogen is converted to the biggest extent to acid gases (NO_X and SO_X respectively) that are essential for the formation of acid rain. In a controlled environment like for example in electricity generation plants, these pollutants can be reduced by the appropriate adjustment of the combustion reactor – process, and by several exhaust purifiers (electrostatic precipitators, bag filters, Selective Non Catalytic Reduction units, or Selective Catalytic Reduction units).

Water quality impacts

Generally, the water requirements for an oil shale industry are estimated to range between one to three barrels of water per barrel of shale oil produced. These water quantities are needed to support processes like power generation for in situ heating, retorting, refining, reclamation, dust control and the demands of the on site personnel. In most applications, river water is used to cover these requirements. As oil shale technology becomes more mature water resources are expected to be used more efficiently by improving for example techniques that recover the water content of oil shales (typically 2 to 5 gallons of water are contained in every ton of oil shale) or by recycling more quantities of process water.

The huge quantities of solid waste that result from the ex situ production processes of shale oil, when gathered in waste piles they constitute serious threat for ground and surface water contamination. Oil shale processing wastes are contaminated with soluble salts, organic compounds, and trace concentrations of several heavy metals. Any possible leakage that could occur from rainfall or snowmelt may result in considerable pollution of aquifers and surface streams with carcinogens and mutagens substances. The factors that determine the degree of risk for water contamination are the oil shale characteristics, the local rainfall patterns, the local topography, the characteristics of the site drainage and the techniques for the prevention of leaching that are applied. Recovery work may include appropriate chemical treatment and management of contaminated water resources. Concerning in situ production, the retorted shale is exposed to potential ground water infiltration which is difficult to be defined and controlled due to lack of accessibility.

Land quality impacts

The most serious environmental issue related to shale oil production is the disposal of the enormous volumes of solid wastes that derive from underground and surface excavation operations and from the inorganic quantities (rock waste) that remain after the pyrolysis process (retorting). Especially in ex situ production techniques, the volumes of the mined overburden may be many times the volumes of oil shale extracted. Concerning underground mining, the factor of potential vertical or

horizontal displacement of the ground surface should be taken into consideration that can result in structural damages of infrastructure like roads, railroads, pipelines and buildings. Prevention of a potential subsidence is done by a limitation in the underground dimensions and by backfilling the mined areas with volumes of solid mine waste. After the completion of the mining activity, operations for the reclamation of the land are required that involve top soil and subsoil backfilling, revegetation of the land, enrichment of the soil (if recultivation is planned) and construction of parks for recreation among others. Generally, it has been proved that land restoration reduces the potential for land destruction and pollution hazards.

2.3 Tight Oil

2.3.1 Tight oil definition

Tight oil constitutes the portion of unconventional oil resources that is most similar to conventional ones. For this reason, commercial tight oil production seems to be the most promising when compared with the development perspectives of the rest unconventional oil resources. Tight oil can be defined as these oil resources that are accumulated in low porosity ($< 12\%$) and low permeability ($< 0,1$ Md) rock formations (shales, siltstones, sandstones, carbonates) where TOC is at least 1%. Generally, the average values for the porosity of tight oil reservoirs can be considered to be between 5% and 7% and average values for the TOC, between 2% and 5%. Just to have an order of magnitude, in **Figure 2.8** the average global distribution of permeability vs porosity for conventional oil reservoirs, is illustrated [11]. The continuous lines represent P50 means that 50% of the reservoirs have permeability greater than this value. The upper pair of dotted lines is for P10 and the lower for P90 respectively. The rock formation where tight oil can be accumulated may be a source rock or a tight reservoir near by the source rock. Tight oils are typically light and sweet (API gravity greater than 31 °API and sulphur content less than 0,5%). For example, tight oils that are being produced in USA demonstrate a specific gravity that range between 40 - 45 °API. [12] They require very little refinement but they are found in formations whose properties prohibit conventional recovery and they require specific stimulation techniques.
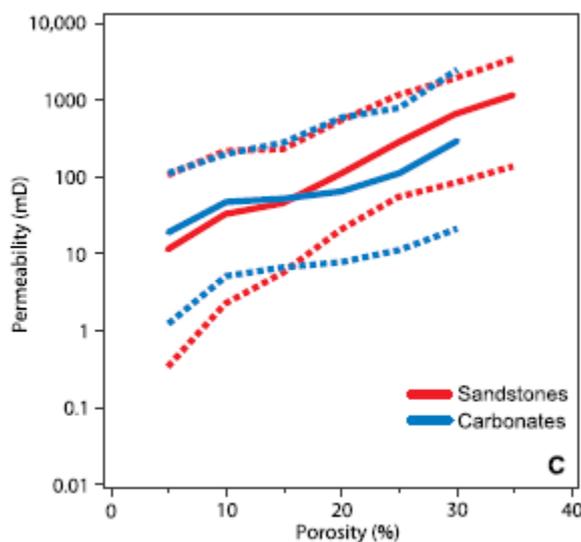
Figure 2.8: Arithmetic average permeability vs average porosity for global petroleum reservoirs composed of sandstone or carbonate

2.3.2   Formation of tight oil

Theoretically, based on source – reservoir spatial relationship tight oil reservoirs (plays) can be distinguished in eight different types as described below. In real conditions, the lithology may vary significantly in the vertical direction and multiple combinations of tight oil plays may coexist.

Concerning the first three tight oil plays means *above source play* (**1**), *below source play* (**2**) and *beside source play* (**3**) the source rock is completely separated from the tight oil reservoir. The tight oil has migrated from the source rock where it has been generated and has accumulated in formations with relatively higher porosity as it happens in conventional oil plays with the difference that tight oil reservoirs have significantly lower porosity and permeability from the conventional crude oil reservoirs.

1. Above source play
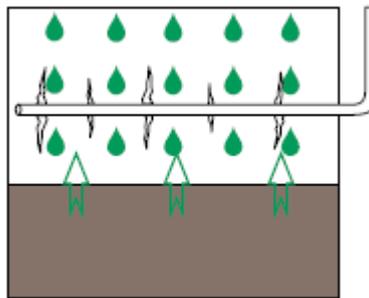
For *above source play*, the tight oil reservoir overlies the source rock. In the tight oil reservoir, the oil migration is very restricted and is controlled partially by buoyancy (Reference case: Cleveland tight oil play in the Anadarko Basin, USA).

2. Below source play
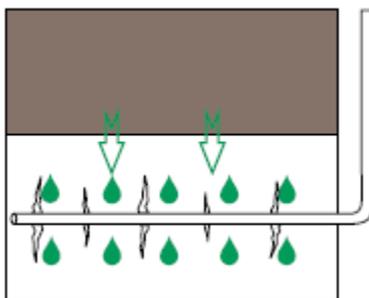
For *below source play*, the tight oil reservoir rock lies beneath the source rock. The oil migrates due to the pressure difference between the source rock and the tight oil reservoir (Reference case: Three Forks tight oil play in the Williston Basin, USA).

3. Beside source play
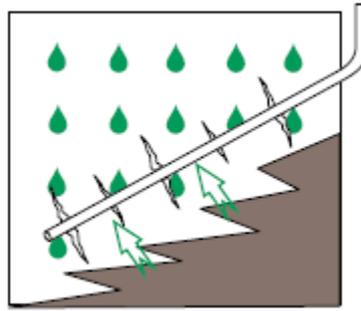
For *beside source play*, oil migrates laterally from the source rocks to the tight oil reservoir rocks which usually exhibit large thickness - more than 100 metres. (Reference case: Granite Wash tight oil play in the Anadarko Basin, USA).

4. Between source play
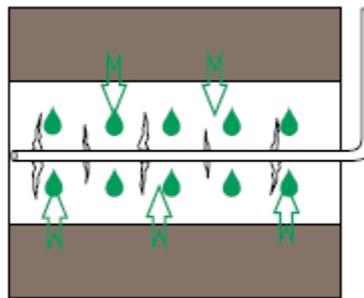
For *between source play*, a reservoir rock is supplied with tight oil from an upper and from a lower source rock at the same time making this tight oil play very promising for commercial development. Usually, the layer of the reservoir rock is very thick - more than 2 metres. (Reference case: Bakken tight oil play in the Williston Basin, USA).

5. In source play
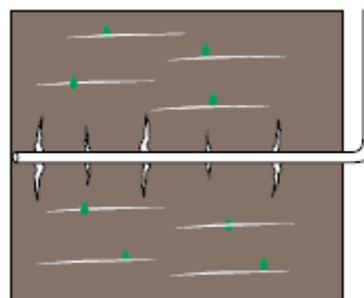
In this type of tight oil play, the source rock serves as a reservoir rock at the same time because a separate rock formation of higher porosity has not been developed. (Reference case: Woodford tight oil play in the Anadarko Basin, USA)

When the rock formation is consisted of successive layers of source rocks followed by layers of reservoir rocks of small thickness (less than 2 metres) then the following three tight oil plays are formed. By increasing the relevant thickness of the reservoir rock we can distinguish the *in source mud dominated* play (**6**) that approximates to source rocks, the *interbedded source rock* play (**7**) and finally the *in-source mud-dominated* play (**8**) which approximates more to reservoir rocks.

6. In source mud dominated play
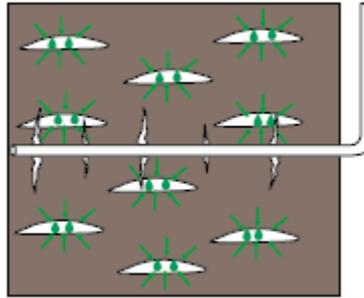
For *in source mud dominated play* the source rock – usually shale, includes thin layers of tight reservoir rocks - usually sandstone or carbonate. The source rock – total formation thickness ratio varies between 0,6 and 0,9. (Reference case: Montney tight oil play in the Alberta Basin, Canada).

7. In source interbedded play
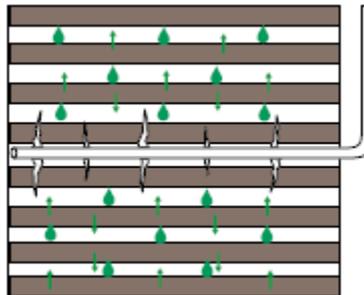
For *interbedded-source play* the layers of source rock alternate vertically with layers of reservoir rock in roughly equal ratios. A basic characteristic is the low thickness of the altered layers that make difficult to distinguish source rocks from reservoir rocks. Usually, the source rock – total formation thickness ratio varies between 0,4 and 0,6. In this tight oil play, the oil content is higher in the middle so during horizontal drilling, the wells penetrate the middle of the formation. (Reference case: Wolfcamp tight oil play in the Permian Basin, USA).

8. In source mud subordinated play
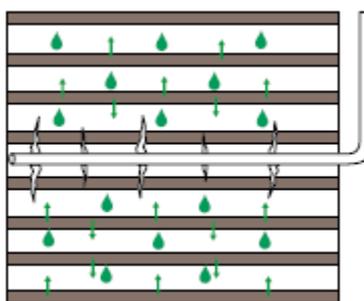
For *in source mud subordinated play* the layers of source rock alternate vertically with layers of reservoir rock with a source rock – total formation thickness ratio below 0,4. (Reference case: Niobrara tight oil play in the Denver Basin, USA). The basic principles that make a tight oil play favourable for commercial oil production are presented below. Nowadays, based on the application of these principles, high production is achieved in tight oil reservoirs with *between source play*, followed by *in source interbedded* and *in source mud subordinated* play. In **Table 2.9** all possible tight oil plays are illustrated and the single well production performance is compared for every case. [13]

- The bigger is the contact area between the tight oil reservoir and the source rock, the most favourable it is for oil expulsion from the source rock.

- The migration of oil from the source rock to the tight oil reservoir is partially controlled by buoyancy. That means that an upward oil supply is more favourable than lateral oil and finally the worst case is the downward oil supply.

- Low clay and high brittle materials content (dolomite, quartz, feldspar) favours the implementation of hydraulic fracturing and other stimulation techniques.

Table 2.9: Classification of tight oil plays in terms of productivity

Tight oil plays	Initial Production rate	Estimated Ultimate Recovery
Between source plays In source interbedded plays In source mud subordinated plays	200 – 400 bbl/day	150 – 300 Mbbl
Above source plays Below source plays Beside source plays	150 – 250 bbl/day	50 – 150 Mbbl
In source plays In source mud dominated plays	100 – 150 bbl/day	30 – 100 Mbbl

2.3.3 Global tight oil reserves

According to BP Energy Outlook, currently, (2015 data) the global tight oil production is around 4,3 Mbbl /day and is expected to increase with high rates till 10 Mbbl /day by 2035 accounting for 10% of the global liquid production as it is illustrated in **Figure 2.9** [13].The main drive for the increase of the tight oil production is the technological innovation that unlocks vast resources and increases the productivity gains. Nowadays, approximately, 90% of the global tight oil production is taking place at the tight oil formations of the U.S.A. but this percentage share is expected to decrease the following years due to the increasing tight oil production in the rest of the world.
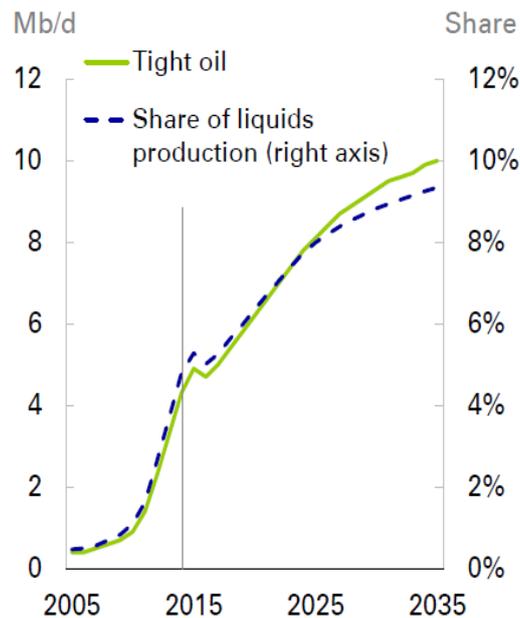
Figure 2.9: Global tight oil production

According to *Classification and characteristics of tight oil plays* a paper that was published online (Springer Link) at January of 2016 the global tight oil potential is estimated (by volume method) to be around 240 billion barrels [14]. Generally, the tight oil plays in North and South America are the most promising for commercial development due to their relatively high reservoir porosity. The distribution of tight oil resources are illustrated in **Figure 2.10**.
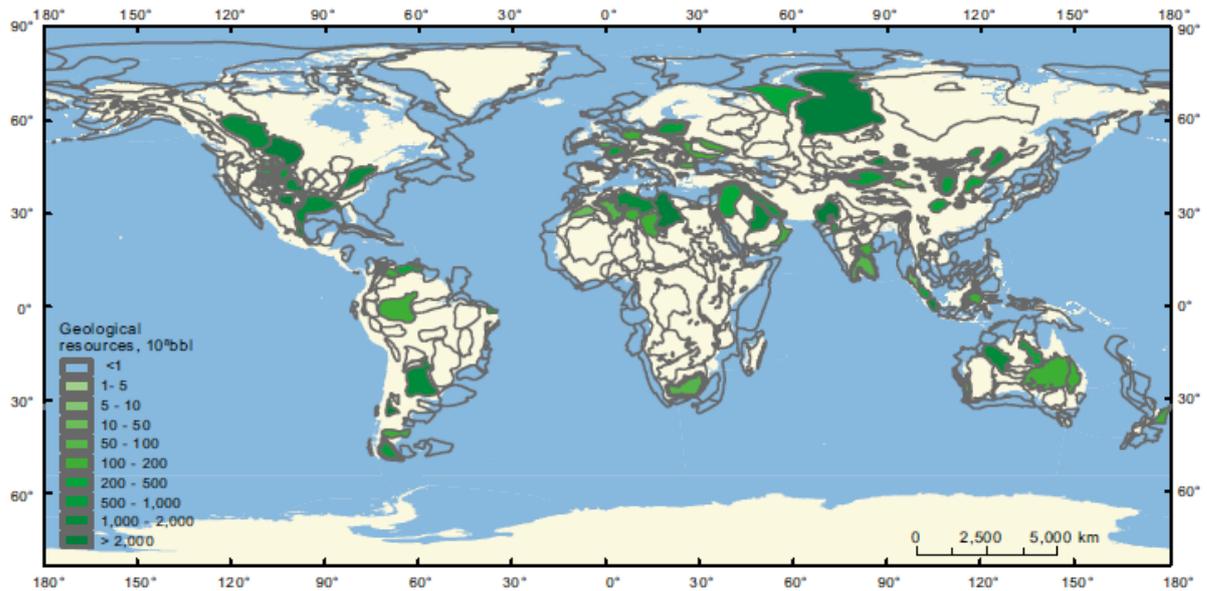
Figure 2.10: Distribution of tight oil resources

2.3.4 Production techniques

Nowadays, the only way to extract tight oil in commercially quantities is by a combination of **Horizontal Drilling** and **Hydraulic Fracturing** (Fracking).

The purpose of horizontal drilling is to increase the contact surface between the wellbore and the tight oil reservoir. The first part of the procedure includes the construction of a vertical well to a depth where a tight oil reservoir is detected. This may happen at a depth typically 1 to 3 km subsurface. When a tight oil play is detected (usually *between source plays* or *in source interbedded plays* or *in source mud subordinated plays*) then the direction of the well is altered (at kick off point) so as to proceed within the limits set by the thickness of the tight oil reservoir. The horizontal leg (part) of the well can extend up to 3 -4 km and it follows the natural fractures of the rock formation (usually shale) Multiple horizontal wells starting from the same vertical well and spreading to different directions is also a possible technique.

The petrophysical attributes of the tight oil reservoirs (low porosity and permeability) do not allow the tight oil quantities to flow to the wellbore at economic rates. In order to increase artificially the permeability of the tight oil formations multistage hydraulic fracturing techniques are implemented. More specifically, as hydraulic fracturing, can be defined the process where pressure is transmitted by fluid or gas (hydraulic) to the rock formation in order to create cracks and allow the hydrocarbons to flow more easily and from a larger volume of the reservoir. Hydraulic fracturing involves the following processes:

1. Perforations are made with a perforation gun at select points along the production casing. Small holes are created at a short distance into the shale.

2. Injection of the fracturing fluid to create and propagate the fractures till a certain extent. The fracturing process includes separated - multiple stages. Using

packers and plugs for isolation, hydraulic fracturing is not implemented at once, but in stages, for a better control of the procedure. The fracturing fluid is injected at constant rates to fulfill the new volumes created and to replace the fluid losses to the formation. The fracturing fluid can be water based (which is the most common), oil based or gases can be used like carbon dioxide, nitrogen or propane. The type of the fracturing fluid to be used, depends on the reservoir's properties.

3. After the creation of the fractures, proppant material (sand or ceramic beads) is injected as part of the fracturing fluid. The proppant material is driven and is deposited along the fracture network.

4. The pumping is ceased and the fracturing fluid is recovered to the surface while the proppant material remains in the fractures maintaining them open.

A basic characteristic of the hydraulically fractured tight oil wells is that they have a very high depletion rate. For example, in the Bakken field in USA, production declines 45% per year when in a typical conventional oil production decline is around 5% per year. [12] Another comment to be made is that even after drilling long horizontal wells and the implementation of the hydraulic fracturing process, the primary Recovery Factor of tight oil reservoirs remains extremely low, ranging between 5 – 10% of the original oil in place and giving a strong potential for the implementation of EOR techniques. Concerning the production cost it is estimated that crude oil prices needs to be above $ 50/bbl for new tight oil exploration and production to be profitable. [12] In **Figure 2.11** an implementation of the hydraulic fracturing technique is illustrated in an horizontal well.
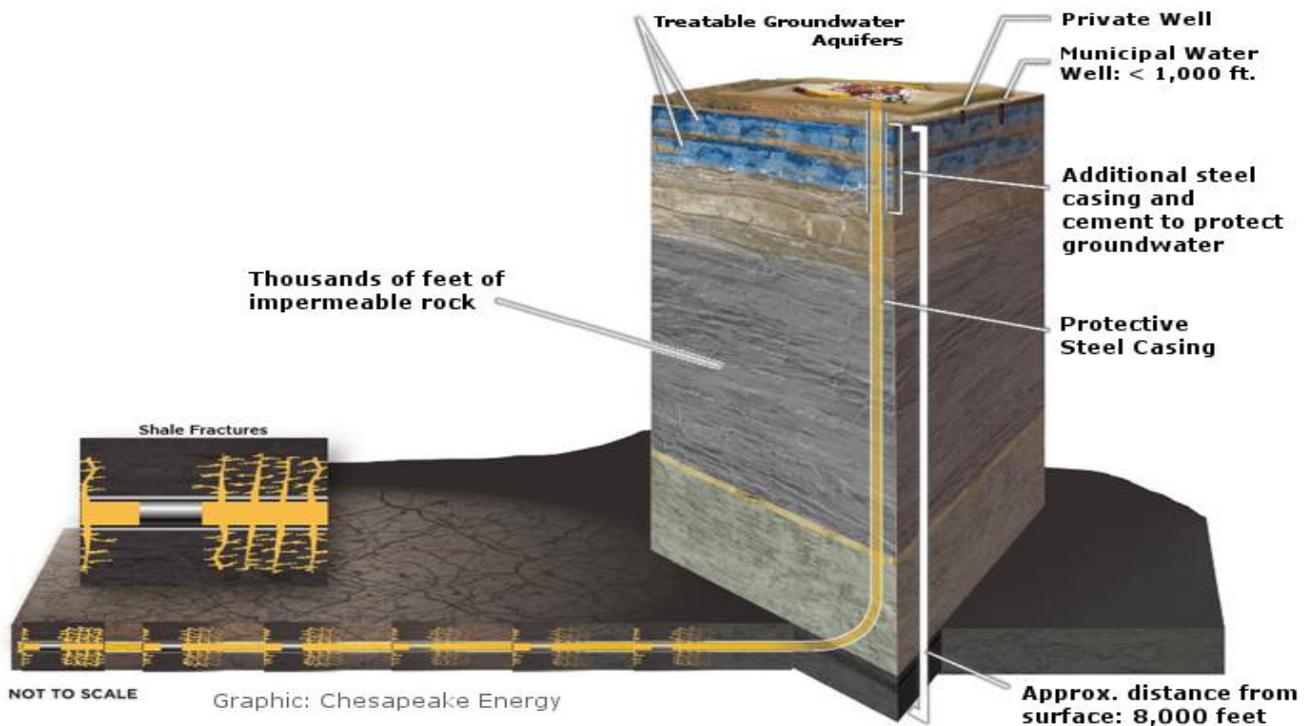
Figure 2.11: Fractured horizontal well

2.3.5   Environmental impacts

Air quality impacts

Many studies that have been conducted (mostly in U.S.A.) confirm the fact that hydraulic fracturing process contributes significantly to poor air quality levels. The sources of air pollutants resulting from hydraulic fracturing process are presented below:

- The waste waters that have significant concentrations of chemical and organic compounds are accumulated in ponds in the surface forming an emission source of volatile carcinogenic and neurotoxin substances. (CH_4, benzene, xylene)

- The drilling equipment and the compressor stations (needed to increase the pressure of the fracturing fluid) are powered by combustion engines. It is widely known that the use of combustion engines consume large amounts of fuels with the resulted emissions (CO_2, SO_X, NO_X, particulate matter, etc). Also, the emissions resulting from the frequent transport activity (trucks) must be mentioned.

- Accidents related to human mistakes can lead to well blow outs, explosions, or fires which can result to uncontrolled release of gaseous hydrocarbons.

Water quality impacts

Hydraulic fracturing is a technique the implementation of which **requires huge quantities of water.** Quantities of water are needed during the drilling process to open the wellbore but the most water demanding process is the stimulation of the well. In **Table 2.10** the water consumption of an average well in four different shale plays is illustrated. The data is provided by Chesapeake Energy, the second biggest producer of unconventional tight gas and oil in USA. [15]

Table 2.10: Water consumption for different shale plays

Water consumption per well (million gal)			
Shale play	Drilling	Hydraulic Fracturing	Total
Barnett	0,3	3,8	4,1
Fayetteville	0,1	4	4,1
Haynesville	0,6	5	5,6
Marcellus	0,1	5,5	5,6

The biggest environmental problem hydraulic fracturing involves is the **risk for ground water contamination.** The fracturing fluid, which most of the times is water based, is consisted 98 to 99,5% of water and the rest 0,5 to 2% is filled with chemical additives. The kind of chemical additives that are used each time depend on the condition of the formation that is going to be fractured and serves a specific purpose. Friction reducing additives, biocides to prevent micro organism growth, oxygen scavengers, acids and corrosion inhibitors are the main groups of chemicals that are used as additives. Moreover, after the end of the fracturing process, the fracturing fluid

is driven back to the surface contaminated with heavy metals (like chromium, mercury and arsenic), naturally occurring radioactive materials (N.O.R.M. like uranium, thorium and radium) and saturared hydrocarbons (like the carcinogens toluene and ethyl benzene) from the deposit. Ground water intrusions have been detected (methane, chloride and other chemical contaminations) in some cases in areas in U.S.A. with hydraulic fracturing operations but they are attributed to human mistakes and consider being avoidable. From the research that has been conducted it can be pointed out that the incidences of ground water contamination that have been recorded are very small compared to the number of hydraulically fractured wells. [16] [17]

The possible ways for an aquifer to get contaminated is by:

- Damage to insulation of the vertical well (cementation or casing). Usually multiple sets of steel casing and cement are installed for preventing any possible leakage as it is presented at **Figure 2.12**

- Accidents related to human mistakes can lead to well blow outs which can result to uncontrolled release of waste waters.

- Accident related to human mistakes can lead to improper waste water disposal and leakages. Normally, between 20% and 50% of the water quantities used for hydraulic fracturing flow back to the surface after the end of the procedure. These huge quantities of waste water are accumulated in open pits for treatment. A (costly) solution for the appropriate disposal of the waste water quantities that result is to recycle them in future hydraulic fracturing operations.

- Uncontrolled subsurface flow through artificial or natural cracks of formations which is very unlikely to happen because hydraulic fracturing process usually takes place at depths 1000 to 3000 metres above ground, when water aquifers are located at smaller depths around 100 metres above ground as it is illustrated at **Figure 2.11**. Also in the interface many impermeable formations exist.
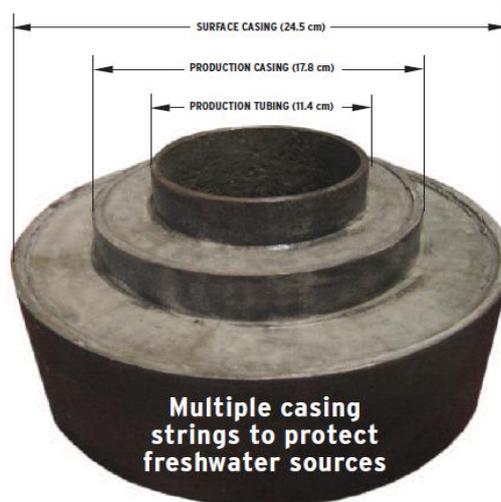
Figure 2.12: Multiple casing strings to protect freshwater sources

Land quality impacts

Tight oil extraction is an activity that requires **high well density** with vertical wells to be more densely drilled than horizontal wells. Consumption and disturbance of the landscape is caused by:

- Installation of the rig pads, the auxiliary technical equipment and pipelines.

- Installation of tanks / ponds for hydraulic fluids storage or waste water treatment.

- Construction of the necessary roads.

Surface disturbance can be minimized significantly when multiple horizontal wells end to a common rig pad. For an order of magnitude, a typical multi well pad needs between 4 – 5 acres during drilling and fracturing and around 1 – 3 acres during production. [16]

The total environmental impacts to the air, the water and the land resulting from hydraulic fracturing operations are illustrated at **Figure 2.13**
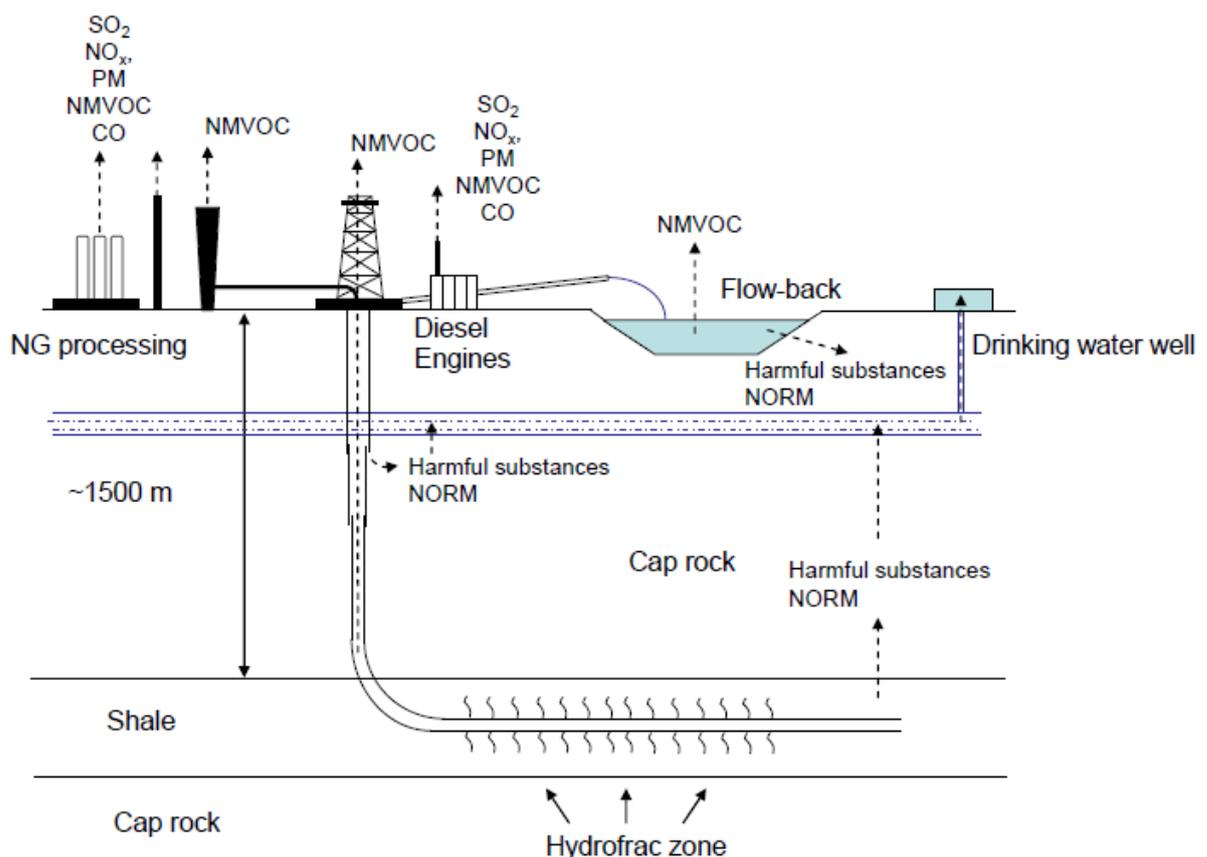
Figure 2.13: Environmental impacts of hydraulic fracturing

2.4 EOR for unconventional oil reserves

In **Figure 2.14** the world oil production curve is illustrated, based on BP - 2015 data. [18] It can be seen that in 2015 the total world oil production was 95.81 million barrels per day and the production cost for all this quantity was ranging from around 5 $/bbl to 95 $/bbl depending on the quality - accessibility of the oil reserves. As far as the unconventional oil production is concerned it can be underlined that the cost of tight oil production is the most close to the cost of conventional oil production ranging around 50 $/bbl. Producing oil from oil sands was the most expensive with process ranging around 70 $/bbl. Finally, in 2015 there was no commercial shale oil production. From all the above analysis the following deductions can be made concerning the implementation of EOR methods in unconventional oil reserves. It must be mentioned that nowadays, the modernization and implementation of EOR technologies have gained the interest of the world leading oil companies.

- **Thermal methods** are implemented in tar sands and in shale oil reserves (and in extra heavy oil). As mentioned in *Chapter 1* the majority of the EOR oil production nowadays, relies on the thermal projects means that this technology is the most mature from all the EOR methods. Also, the quantities of the unconventional oil reserves they are addressing to are enormous and spread all over the world. But, the fact that the production cost of these unconventional oil reserves is high lowers the attractiveness for oil companies to invest in thermal methods of oil recovery, at least for the near future.

- **Miscible gas injection methods** have the larger potential for economical development in the near future as they are implemented in tight oil reserves which have production cost that approaches more that of conventional oil reserves.

- **Chemical methods** do not have a significant potential in the exploitation of unconventional oil reserves because they are more costly and they need to be implemented in formations of high permeability and porosity.
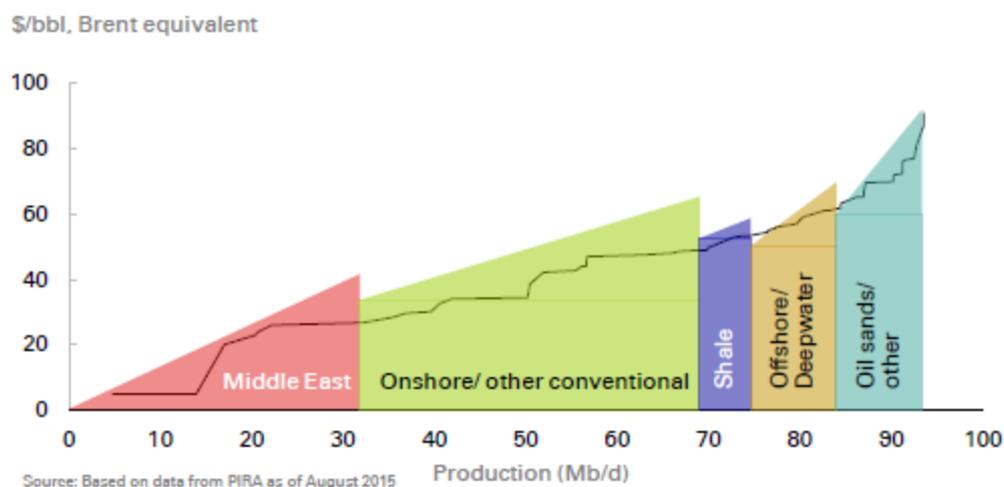
Figure 2.14: Oil production cost curve - 2015 data

2.5 Appendix

Oil Upgrading is a process that converts raw bitumen to **synthetic crude oil** in order to be accepted and processed by the common refineries. Synthetic oil is usually low in sulphur and contains no residue or very heavy components. Oil Upgrading is performed in two stages, known as primary and secondary refining. Primary refining aims to break the long carbon chains into shorter ones. Secondary refining aims to the removal of impurities such as sulphur, nitrogen, and heavy metals. Upgrading can occur at or near the producing area or the refinery.

Technically recoverable resources represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs.

Economically recoverable resources are resources that can be profitably produced under current market conditions.

Fischer Assay is used to measure the potential oil yield (as a weight percent) from oil shale.

TOC (Total Organic Carbon) is the quantity of carbon that is found in the molecules of the organic portion of a source rock. Usually is found as a weight percentage.

Volumetric method for oil reserves estimation is preliminarily method for estimating the amount of hydrocarbons in place. It includes calculation of the dimensions of the reservoir, the total rock pore volume and finally the fluid content within the pore volume. After the volumetric method decline analysis and material balance methods are applied for more accurate estimations.

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Chapter 3 EOR – Thermal methods

3.1 Introduction

Thermal oil recovery methods, regardless the technology applied, aim to provide thermal energy to a specific part of the reservoir. The increase in the temperature of the reservoir has as a result changes on the hydrodynamic properties of the hydrocarbons that subsequently increase (or even start) the rate of oil production.

Thermal EOR methods are primarily implemented in unconventional oil reserves (tar sands and oil shales) and in conventional oil reserves (heavy and extra heavy oil accumulations with °API ranking between 10° and 20°). As it has already presented in Chapter1 : *Introduction*, **Figure 1.8** around 66% of the nowadays EOR oil production comes from the thermal projects (2 million barrels of daily production from thermal projects over 3 million barrels of daily production by all the EOR methods). Nowadays, the majority of the thermal EOR projects are concentrated in Russia and in Canada. Thermal Recovery methods can be distinguished in three different categories as indicated below:

A. **Hot fluid displacement** methods where the heat needed for the reservoir stimulation is generated at surface facilities and a heat carrier (fluid) is injected in the formation.

B. **In - situ combustion** methods where the heat needed for the reservoir stimulation is generated in the reservoir by exothermic reactions (combustion).

C. **Electric heating** methods where the heat needed for the reservoir stimulation is provided by the electric energy of alternated currents.

The majority of the commercial thermal EOR projects nowadays use the hot fluid displacement methods and most specifically, when steam is used as fluid for both heavy and light enhanced oil recovery. In situ combustion methods are generally more complicated methods and demonstrate some advantages in the deep formations. Finally, the electric heating methods constitute a relative new approach that has not implemented commercially yet to the real fields. However it demonstrates some advantages over low quality formations where the previous methods are not effective. In the **Table 3.1** some general criteria of the thermal EOR methods are presented (NC – Not Crucial). [27]

General criteria for Thermal EOR methods

EOR method	° API	Depth (m)	Porosity	Thickness (m)	Viscosity (cp)	Permeability (md)
Hot fluid displacement	8 - 13.5	<1500	>20%	>6	200-3000	250-1000
In situ combustion	10 - 16	<3500	>20%	>3	1500-5000	>50
Electrical	>7	NC	NC	NC	>50	NC

Generally speaking, the flow of the hydrocarbons in a porous reservoir is described by several variations of the Darcy's law that is presented in **Figure 3.1.** It can be seen that the volume flow rate or production rate **(Q)** is directly proportional to the fluid permeability **(K)** and inversely proportional to the viscosity of the fluid **(μ)**. Concerning the other variables, (L) is the distance the fluid has to cover, (A) is the surface area exposed, (ΔP) the pressure drop. From all the above it is obvious that the temperature of the hydrocarbons is purposely increased using thermal methods in order to affect the variables (K) and (μ). More specifically, in real reservoirs where there is diphasic flow (oil and water) we are interested in increasing the relative permeability of the oil K_{ro} and decreasing the viscosity of the oil $μ_o$.

$$Q = \frac{-kA\,(\Delta P)}{\mu L}$$

Figure 3.1: Darcy's Law

The property of oil that is affected more by an increase of temperature is the **viscosity** which decreases exponentially. Generally, the more viscous a fluid is, the greater the viscosity reduction will be after a given temperature increase. The previous characteristic affects the relevant viscosity ($μ_o$ / $μ_w$) of the two fluids that exist in the reservoir's pores favouring the flow of oil more than the flow of water. In **Figure 3.2** the decrease of the viscosity ratio ($μ_o$ / $μ_w$) resulting from an increase in temperature is illustrated (for Bradford crude 1700 cP oil). Certain light oils exhibit an inverse behavior but this is the exception (dashed line for crude 3 cP oil). [1] It must also be mentioned, that certain gases when absorbed by the liquid hydrocarbons, have the ability to enhance the viscosity reduction. For example, the quantities of CO_2 that are produced during in situ combustion reinforce the effect of the temperature increase in the reduction of oil viscosity. The reduction of the viscosity ratio (which can be considered as the direct effect of the temperature increase) is the main reason for the increase of relative permeability of oil that is described below.
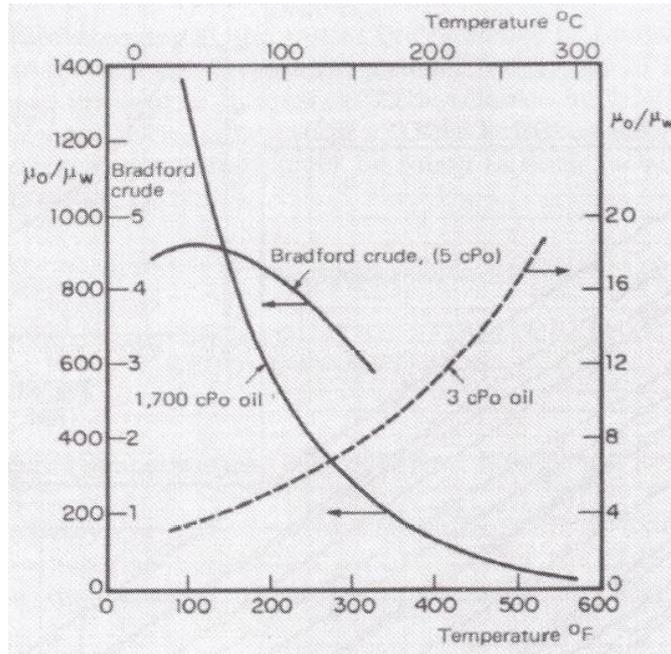
Figure 3.2: Decrease in the viscosity ratio as temperature increases

Several studies to investigate the effect of temperature on the **relative permeability** have been conducted like the paper *Relative permeability curves for high pressure, high temperature reservoir conditions* that was published in Oil and Gas Business in 2008. According to this paper, experiments that were performed at water-wet sandstones at reservoir pressure (fluid pressure 300 psig and overburden pressure 650 psig) prove that water/oil relative permeability curves are affected by the parameter of temperature. In **Figure 3.3** we can see that for increased temperature (70 °C) the water/oil relative permeability curve at lower values when compared the lower temperature (23 °C) curve at all water saturations. To sum up, the oil relative permeability increases at all oil saturations when the temperature is raised and by this way the oil displacement efficiency is improved. [3]
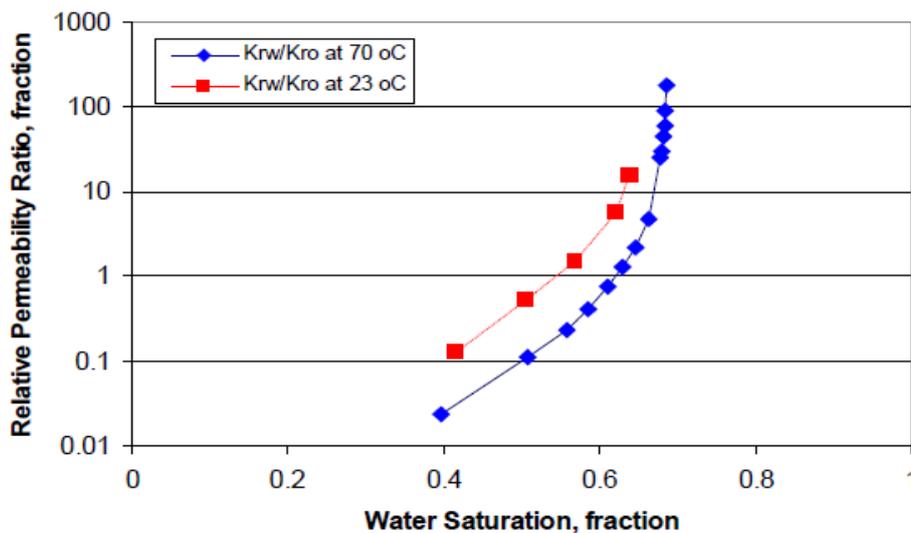
Figure 3.3: Effect of temperature on relative permeability ratio curves at reservoir conditions

The increase of temperature, affects not only the hydrodynamic properties of the hydrocarbons as described above, but also the thermal properties of the oil and the reservoir. In **Table 3.1** the differences in the average **volume expansion** coefficients are illustrated for the different materials of the reservoir. It can be seen that oil expands more for the same increase of temperature when compared with the expansion of water and the porous medium. That means that the increase of temperature encourages more the expulsion of oil from the pore space. [1]

<div align="center">

Table 3.2: Average volume expansion coefficients for the materials in the reservoir

Material	Average Volume Expansion Coefficient (1/°C)
Oil	10^{-3}
Water	$3 * 10^{-4}$
Sandstones	10^{-5}

</div>

The differential thermal stresses between the heated and the cold areas of the rock formation caused by the hot fluid injection process affects also the mechanical properties of the rock. Numerous shear zones are formed in the rock increasing by this way the porosity and the permeability of the affected area. The **shear distortion** area is presented in **Figure 3.4** next to the heated zone of the reservoir. According to the book *Heavy Oils: Reservoir characterization and production monitoring* the shear distortion that thermal processes cause can result in increase of the rock's permeability by a factor 2 to10 that enhances the movement of the hydrocarbons. The porosity is also affected. In the case of Athabasca oil sands for example shear distortion is able to increase the porosity from 30% to 35%. [2]
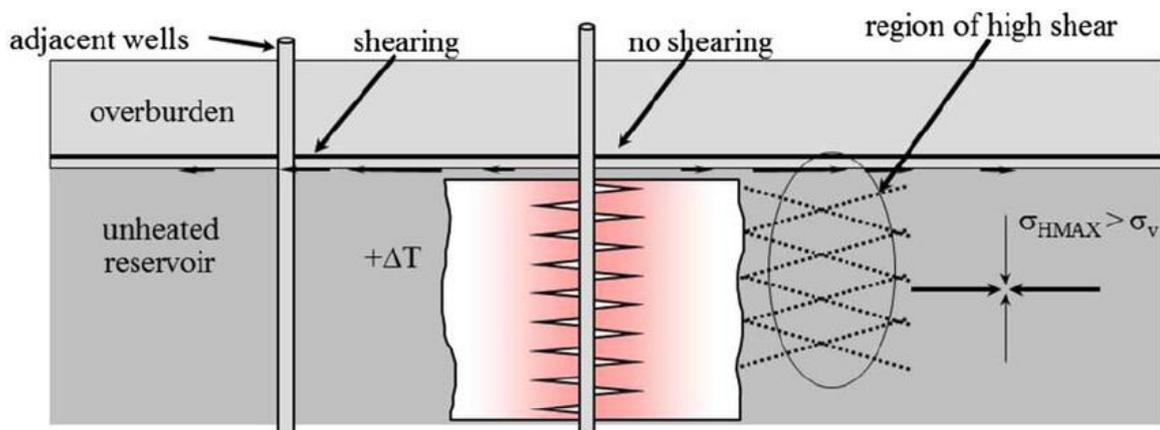
Figure 3.4: Shear distortion area next to the heated zone of the reservoir

3.2 Hot fluid displacement methods

The hot fluid displacement methods stimulate the reservoir by a combination of two mechanisms that act simultaneously and enhance both the oil recovery.

- Transfer of **heat** to the oil reserves

- Transfer of **momentum** to increase the oil flow rate towards the production well

The only heat carrier that has ever been used in hot fluid injection methods is **water** whether in vapour or liquid phase, as it is the fluid with the highest heat transport capacity. Hot fluid displacement methods include the following techniques:

1. **Hot water flooding**

2. **Steam flooding**

3. **Cyclic steam stimulation (CSS)**

4. **Steam assisted gravity drainage (SAGD)**

A general characteristic of all hot fluid displacement methods is that they are energy intensive and that exhibit low degrees of efficiency. As it can been seen from **Figure 3.5** the are significant thermal energy losses during the heating of the fluid and during the transferring of the fluid along the surface injection lines and along the well bore to the target area of the reservoir. Moreover, due to the fact that the heat transfer in the formation cannot be controlled with accuracy, significant quantities of heat are transferred inevitably, away from the target zone for example, to the impermeable cap or base rock. It is a fact, that a small part of the thermal energy generated, is used to heat the hydrocarbons. In the best cases, thermal efficiency can reach 50% with the steam injection methods to exhibit greater effectiveness than hot water injection methods despite of the fact that slim - hole injectors and insulated tubing are used. Generally, the economical feasibility of a heat injection project is determined by the extent of the heat losses during the transfer of the heated fluid to the target zone of the reservoir. From all the above, it can be deducted that hot fluid displacement methods cannot be applied in low thickness formations or in fields where the injection well is far away from the production well.
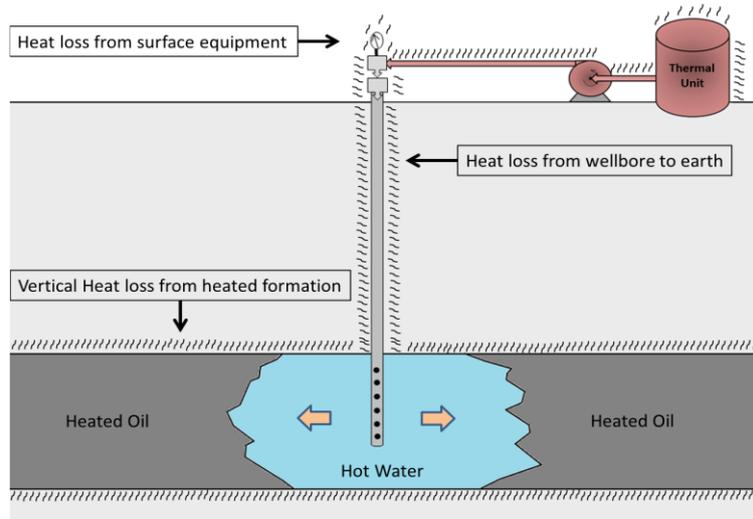
Figure 3.5: Heat losses during hot fluid displacement methods

Each of the hot fluid displacement techniques have been applied numerous times in the fields since 1950s and have demonstrated advantages and disadvantages as it will be described below. Each method manage to displace the hydrocarbons towards the well by using different drive mechanisms that result in different displacement efficiency and subsequently in different ultimate Recovery Factors of the Original Oil In Place as is illustrated in **Table 3.2** [4] [5]

Table 3.3: Comparison of Recovery Factors achieved by every hot fluid displacement method

Hot fluid displacement method	Ultimate Recovery Factor % OOIP
Hot water flooding	30% - 45%
Steam flooding	50% - 60%
Cyclic Steam Stimulation	15% - 40%
Steam Assisted Gravity Drainage	60% - 70%

3.2.1 Hot water flooding
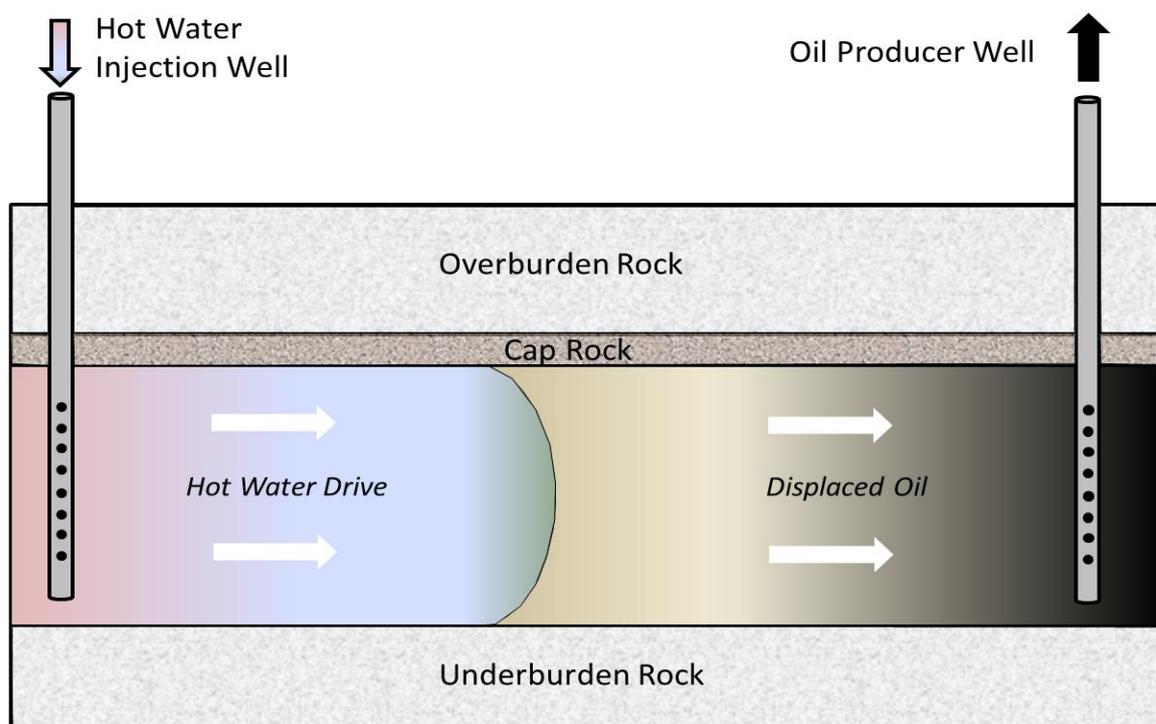
Figure 3.6: Hot water flooding

. **General description of the technique**

Hot water (~ 80 °C) quantities are injected from the injection wells in order to make the oil move towards the production wells. The displacement mechanism of the hot water flooding technique can be distinguished in two stages - zones as the water is spreading into the formation and its temperature is decreasing at the direction of the flow:

1. **Hot water zone** that starts from the injection well and expands as hot water injection continues. When the hot water is injected in the reservoir diffuses and cools down as it comes in contact with the cold rock and hydrocarbons of the formation. The temperature of the hot water is decreasing as it moves in the reservoir and from the other hand the temperature of the solid matrix and the hydrocarbons of the formation is increasing as heat transfer through convection is taking place. The viscosity of oil (μ_o) is decreasing, the relative permeability of oil is increasing (K_{ro}) and subsequently the flow of oil is enhanced. As we move towards the hot water injection well, the temperatures encountered are higher and the oil trapped (residual oil saturation S_o) is decreasing. The heat transfer from the hot water to the formation continues till the equilibration of the temperatures that marks the start of the cold water zone.

2. **Cold water zone** where oil is displaced by water of the same temperature only by transfer of momentum, like as it happens in cold water flooding (a secondary recovery method).

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Just to have an order of magnitude, an average geothermal gradient is around 3°C / 100m. So, if we admit that the oil window (conventional oil formations) is between 1 – 3,5 km then temperatures in conventional oil reservoirs are ranging between 30°C and 105°C as the depth is increasing. That means that when we inject water of environmental temperature in fact we decrease the reservoir's temperature resulting in decrease of the hydrocarbons viscosity and mobility. In **Figure 3.7** the results of simulation experiments that have been conducted by the Institute of Geological Science in Shengli Oilfield, China are presented. The first curve illustrates the increase in displacement efficiency as the pore volume (PV) is increasing when water at the reservoir's temperature is injected (65°C). The second curve illustrates the increase in the displacement efficiency that is achieved when the temperature of water injected is 35°C higher than the reservoir's temperature (100°C). Another deduction from these simulations experiments to be made is that when the pore volume of the reservoir is very small, hot water flooding seems ineffective. [6]
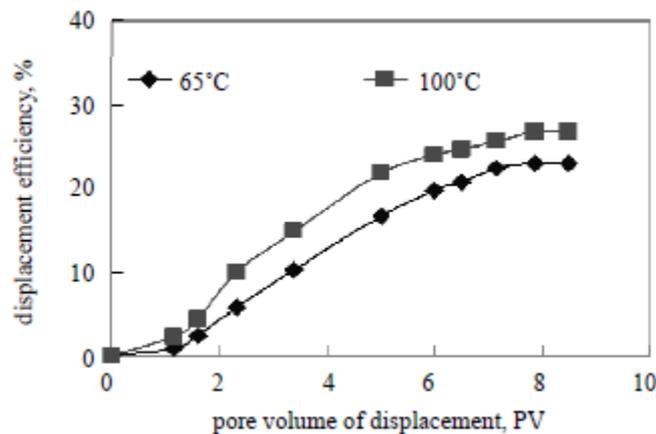
Figure 3.7: Hot water oil expulsion modelling in Gudong Oilfield

Advantages

The first advantage to be mentioned is the relevant simplicity of the technique's implementation ranking hot water injection as the least expensive process from all the thermal EOR methods. Another significant advantage is that hot water is injected in higher pressure when compared with steam injection and is far more efficient in maintaining the pressure of the reservoir.

Disadvantages

Hot water flooding is technique that is very rarely applied at the fields for two main reasons that both do non leave much room for high degrees of efficient thermal oil recovery. The first is that water has very low heat capacity when compared with steam so the heat energy that can be carried is always limited. Secondly, the heat losses by conductivity from the heated water are far more intense than in the case of steam, impeding by this way the effectiveness of the heat transfer to the hydrocarbons. Generally, the

Field application

The hot water injection technique is highly recommended in reservoirs where cold water injection has already been applied during secondary production and in geographical areas where geothermal energy can be used to heat the injection water. By definition hot water injection is operating in lower temperatures than steam injection techniques. So, for the heat transfer between the injected water and the hydrocarbons to be more efficient, it is recommended that hot water injection is applied in reservoirs with relatively large depths with high prevailing pressures. Also hot water injection can be applied in heavy oil reservoirs where steam injection techniques are not recommended. Finally, before applying this method the lithology of the reservoir must be examined because low salinity waters in some circumstances may cause the swelling of the clay matrix which result in the decrease of the reservoir's permeability.

An evaluation of the method when applied in the field is presented in the feasibility study of hot water flooding that was published in SPE Heavy Oil conference in Alberta, Canada (2012). The performance of the method was investigated in a heavy oil reservoir with density 10.6° API and viscosity 13400 mPa * s (at 22°C) that is found in the Lloydminster area in Canada. In this area, reservoirs have low permeability but high porosity (around 30%) and due to low mobility of the oil, the Recovery Factor after primary production varies between 3 and 8% whereas after secondary production can increase up to 15%. The simulations of hot water flooding resulted in a possible Recovery Factor of 30% of the original oil in place. [7]

3.2.2 Steam flooding
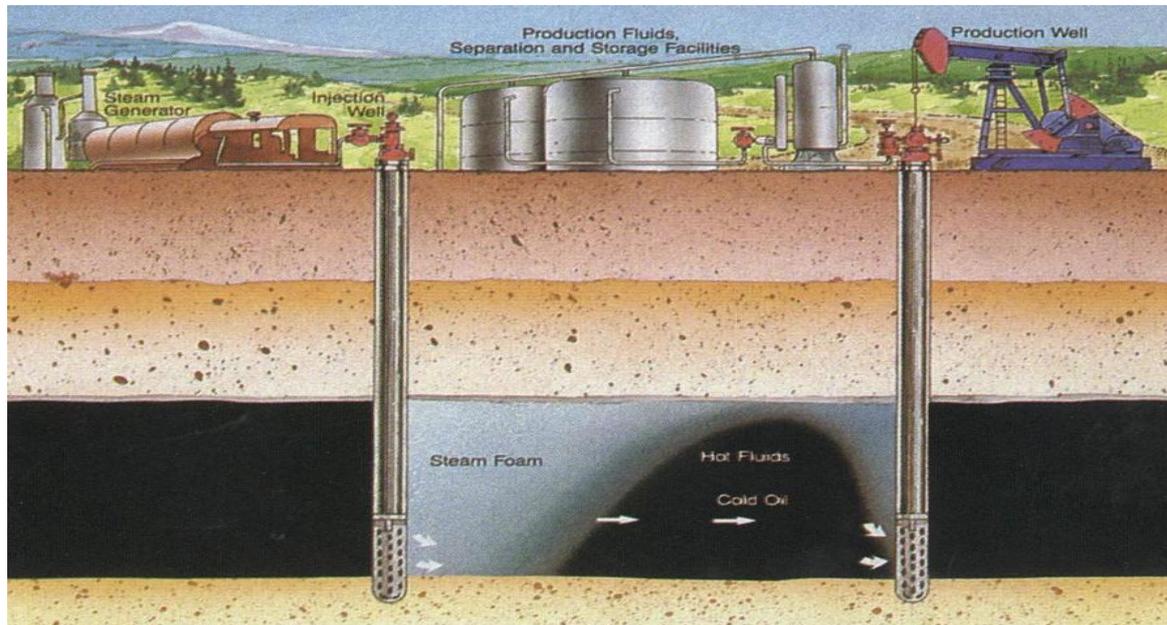
Figure 3.8: Steam flooding

General description of the technique

Steam injection is by definition a more efficient method than hot water flooding. In order to explain the reason, we must trace back to the term of *Recoverable Heat* that is defined as the difference between the enthalpy of the fluid injected and the enthalpy of liquid water in reservoir conditions. The enthalpy of the mixture is given by the following relation:

$$H = H_g + X*L$$

Where:

H_g is the enthalpy of the liquid water at the saturation point.

X is the quality of the saturated steam. For example if the injected steam when generated at the surface contains 90% steam and 10% water then the quality X of the steam is 90%.

L is the latent heat of water vaporization.

From the above it is clear that H will always be grater than H_g means that steam is always carrying more heat energy than saturated water. In practice the recoverable heat when high quality of steam in injected can be more than 3 times greater than in the case of saturated water injection. For this reason steam injection is a more effective way for transferring heat to the hydrocarbons when compared with hot water flooding.

The displacement mechanism of the steam flooding technique can be distinguished in four stages - zones as the steam is spreading into the formation and its

temperature is decreasing at the direction of the flow. The phenomena occurring during stage 3 and 4 are similar with those of hot water flooding process.

1. **Steam zone** is near the injection well where the high temperature steam is injected into the formation. Steam foam is generated, the size of which is determined by the reservoir characteristics and the distance between the injection and the production well as it is illustrated in **Figure 3.8**. The gaseous phase is retained for a distance and the steam's temperature (for example 300°C) is retained practically constant. The temperature of the formation at the steam zone soon rises at the same level and equilibrates with the temperature of the injected steam. At this stage, the light hydrocarbons of the formation evaporate and incorporate to the flow of the steam

2. **Condensation zone** is the next stage. After a distance, the temperature is decreased below the saturation point (for example 250°C) and the steam starts to condensate (and the hydrocarbons evaporated at the previous step as well). The condensation process accelerates as the steam is moving forward till a point where there is no steam any more but only hot water. The vaporization – condensation of the light hydrocarbons constitutes a secondary displacement mechanism of the oil increasing the effectiveness of the method.

3. **Hot water zone** where the displacement of the hydrocarbons is conducted by the heat and momentum transfer of the hot water flow.

4. **Cold water zone** where the displacement of the hydrocarbons is conducted by the momentum transfer of the cold water flow.

Just to have an order of magnitude, for a hydrostatic pressure gradient of 0.43 psi/ft at a depth of 3000 ft the pressure of the hydrocarbons in the pores of the reservoir will be 1299 psia. As we can see from **Figure 3.9** in this pressure the saturation temperature of water is around 550 °F (287°C). From the above it becomes obvious that all steam injection techniques are limited by the depth of the application because of steam's critical pressure.
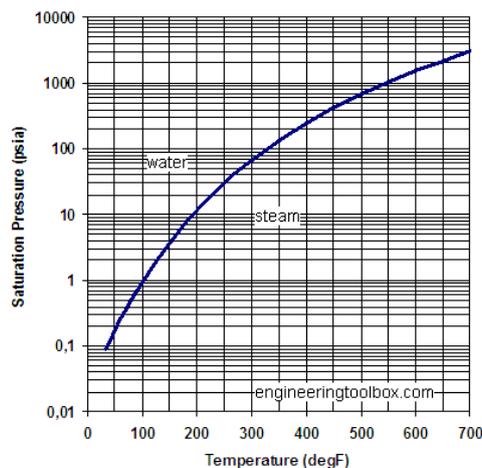
Figure 3.9: Saturation curve of water

Advantages

When compared with hot water flooding, steam injection has some advantages as a method. As it has already described, steam exhibits greater displacement efficiency – more oil is produced, for the following reasons:

- It is more efficient in transferring heat to the hydrocarbons

- Vaporization – condensation of the light hydrocarbons in the steam and condensation zone respectively is a mechanism improving the oil displacement

- It is less prone to preferential channelling than hot water flooding.

Disadvantages

The main disadvantage of steam flooding is that it is very energy intensive method increasing significantly by this way the cost of production. Approximately, one – third of the oil quantities produced must be consumed by the steam generator unit.

Field application

Steam flooding can be an economically viable method when applied in thick, more than 20 ft and shallow deposits buried from 300 to 5000 ft in order to minimize the heat losses. Also the reservoir must exhibit high average oil saturation and permeability more than 200 md. [8] For example, the average oil saturation of the successful steam flood projects is around 63%. [9] Generally, it is applied in sandstones and not in carbonate reservoirs. The *Duri Steamflood Project* in Indonesia is the largest successful thermal Enhanced Oil Recovery project of the world with a daily production of 200.000 bbl of crude oil. [10]

As it has already explained, the steam is injected at relatively high temperatures around 300°C to 400°C with subsequent high amounts of heat transferred to the rock formation. It is a common practice after the implementation of steam flooding to proceed with cold water flooding in order to take advantage of the increased temperature of the rock matrix and to improve furthermore the efficiency of the oil recovery.

3.2.3 Cyclic Steam Stimulation
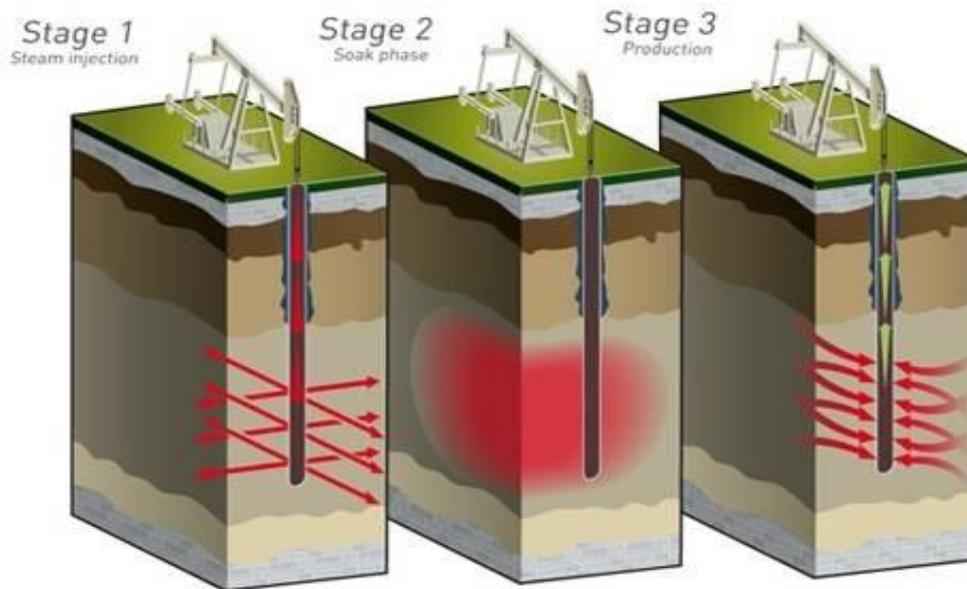
Figure 3.10: Cyclic Steam Stimulation

General description of the technique

The Cyclic Steam Stimulation (CSS) technique was invented almost accidentally in Venezuela, in 1959 when a steam injector started producing oil in larger quantities than the surrounding production wells after a blowout event. Cyclic steam stimulation is a widely used EOR method where only one well is used alternately as steam injector and as a producer. In this technique, oil is produced periodically after the end of a stimulation cycle. The stimulation cycles are repeated several times till oil production becomes too low to support the sustainability of the operations. The number of stimulation cycles is varying but just to have an order of magnitude, the technique can be repeated in the same well 20 or 30 times. A cycle of the cyclic steam stimulation process involves 3 stages that are presented in **Figure 3.10** and are described below:

1. **Steam injection phase** where steam is injected continuously to the formation for a period determined by the reservoir characteristics, usually around a month. The steam diffuses in the formation and the viscosity of the oil starts decreasing due to the rise of the temperature.

2. **Soak phase** is the next stage where the injection of steam is ceased and the well shuts down for a short period of a few days. The steam foam stops expanding and condensates to warm water as heat is transferred to the formation and temperature equilibration is achieved.

3. **Production phase** where the well opens and oil production occurs by natural flow at first and the by artificial lift as it is shown in **Figure 3.10**. The production phase consists of an initial period where part of the condensed water is drilled, a period of stabilized oil production and finally a period where oil production declines till a point where the production phase stops and the cycle is repeated.

If the viscosity of the oil is too high then the oil is not able to flow naturally from the cold zone to the producer well and the production is limited only to the heated area of the reservoir.

Advantages

As it has already described, the basic characteristic of cyclic steam stimulation is that for the implementation of the method only one operational well is required that is used periodically as injector and as producer. This characteristic results in decreased capital and operational expenditures when compared with the rest EOR methods. That means that as an investment is attractive since it has a quick payout. The surface footprint and the environmental impacts are also reduced as a result of the only one well needed. Finally, it must be underlined that cyclic steam stimulation is a mature technique since it has been used extensively in many oilfields increasing by this way the possibilities of success when it is applied.

Disadvantages

The Recovery Factor achieved by the process is very low with values of conventional cyclic steam stimulation to be around 15 % because only a small part of the formation is affected. In order to increase the low Recovery Factor of the Cyclic Steam Stimulation several modern techniques have been integrated to the process with success. It has been proved that it is possible to increase significantly the Recovery Factor from around 15% to 40% if advanced techniques like **hydraulic fracturing**, **horizontal wells**, **admixture of chemical additives to the steam** or **separated zone steam injection** are applied. But even with this possible improvement the resulted Recovery Factor will be less than the other steam injection techniques, as it is presented in **Table 3.2**. For this reason, when cyclic steam stimulation becomes economical not viable other techniques are applied to increase the ultimate Recovery Factor like **CO_2 injection**, **steam flooding** or **in situ combustion** with steam flooding to be the most widely used.

Field application

Cyclic steam stimulation is applied in highly viscous oil formations that are more than 30 ft thick and buried in a depth less than 3000 ft in order to minimize the heat losses. Also, the formation must permit steam distribution and oil movement so a minimum average permeability of 100mD is required. Practically it has been proved that this technique is economically viable in formations with oil saturation more than 40% and porosities more than 30%.[5] Successful, commercial applications of the technique are found in Wolf Lake and Primrose fields in Canada.

In the fields, the use of high pressure steam in cyclic steam stimulation has been proved very efficient and in this case the method is called **High Pressure Cyclic Steam Stimulation** (HPCSS). This method involves only two phases since there is no soak phase. During steam injection phase, steam is injected at pressure capable to fracture the reservoir area near the injection well. In the production phase that follows, a mixture of steam and mobilized hydrocarbons are pumped towards the well. The cycles are repeated till the production of the well becomes economically not viable. When a configuration of vertical wells is used then each well covers a space ranging between 2 and 8 acres. In the case of a horizontal configuration of wells, each well is located 60 to 80 metres away from the other. Approximately, 30% of the sand oil in Alberta, in Canada is produced via this method. [11]

A version of Cyclic Steam Stimulation that is still in pilot stage is the so called **Top Injection Bottom Production** (TINBOP) technique that is illustrated in **Figure 3.11.** As we can see, there is one short and one long string into the well and by using two packers, two volumes are formed an upper and a lower one. At first, steam is injected from both of the strings (warm – up stage). After some days the long string ceases to inject steam and becomes a producer whereas the short string continues to inject steam. After the warm up period stage the normal cyclic operation of the well starts that involves a period of steam injection from the short string (for example 20 days) while the long string is closed, that is followed by a period of oil production from the long string (for example 180 days) while the short string is closed. As one can observe there is no soaking period in process.

A simulation study that was conducted by Texas A&M University and involved two black oil models with specific gravities 9 °API and 12 °API resulted in ultimate Recovery Factors of 3,3% and 14% when conventional Cyclic Steam Stimulation is applied. From the other hand, when Top Injection Bottom Production technique is used, ultimate Recovery Factors of 5,7% and 27% are achieved, means an increase of 57% and 93% respectively. [12]
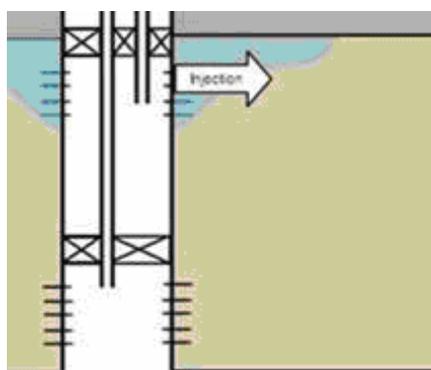
Figure 3.11: Top Injection Bottom Production technique

3.2.4 Steam Assisted Gravity Drainage
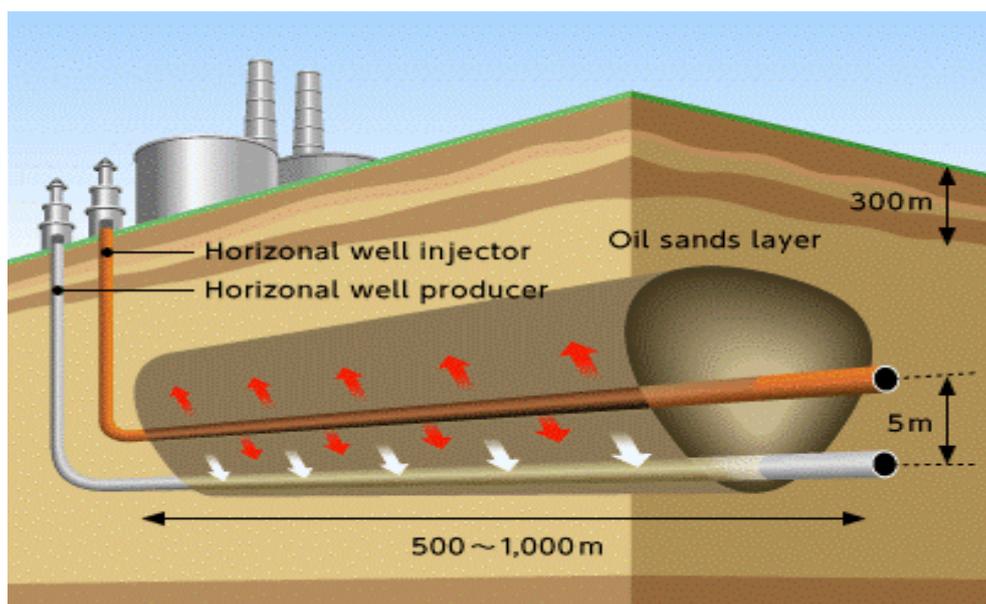
Figure 3.12: Steam Assisted Gravity Drainage

General description of the technique

The Steam Assisted Gravity Drainage is a technique that was first implemented in Alberta oil sands in Canada in the 1970s and since then it become one of the most efficient and reliable technologies for the exploitation of highly viscous oil or oil sands formations. As it is illustrated in **Figure 3.12** this technique involves the drilling of a pair of parallel horizontal wells with a length ranging most of the times from 500 to 1000m or even 1500m into the target hydrocarbon formation. The two horizontal wells are in the same vertical plane and at a small distance from each other ranging from 4 to 6 meters. The upper well serves as steam injector whereas the lower well that is located near the base rock of the formation, as oil producer. In normal operation conditions the upper and lower horizontal wells operate simultaneously. The efficiency of the SAGD technique is measured most of the times by the *Steam Oil ratio*. Nowadays there are SAGD applications that exhibit a Steam Oil ratio around 2 meaning that they need to inject two barrels of water in the form of steam in order to produce one barrel of oil. The less is the Steam Oil ratio the more effective is the process as less thermal energy is required for the production of steam. Concerning the emissions of SAGD technique, are estimated around 0.06 tonnes of CO_2 equivalent per barrel of bitumen produced which approximately the same with the emissions resulting from surface mining and upgrading. [13]Usually, there is a central well pad in the surface where several pairs of horizontal wells end and by this way the land disturbance is minimized as well. The SAGD technique consists of two phases:

1. **Preheating phase** that is necessary during the early stages of the SAGD operation in order to accelerate the heating of the oil formation, the creation of the steam chamber and the resulted oil production. During the preheating phase both of the horizontal wells act as steam injectors. The pressure of the steam

injected is retained constant and below the fracture pressure of the formation since steam has the ability to penetrate the formation and expand. The steam that is injected from both injectors expands upwards (red arrows) in **Figure 3.13** due to its low density forming a steam chamber. As the process continues, the steam chamber grows upwards and sideways. The preheating phase ends when the steam chamber reaches the cap rock at the top of the formation.

2. **Production phase** during which the lower horizontal well stops injecting steam and starts operating as producer. When the steam chamber reaches the cap rock, the steam cools down and condenses. Then, a mixture of condensed water, formation water and mobilized hydrocarbons start flowing downwards, from the top of the formation to the formation base driven by the gravity (green arrows in **Figure 3.13**) towards the production well. It should be mentioned, that gravity drainage is the only driving force of this technique which is very effective as it results in increased oil mobility as the condensed hot water forms a mixture with the bitumen and flow together towards the production well. Up to the surface facilities, the water quantities of the mixture are separated and are sent to the steam generators whereas the bitumen must undergo oil upgrading to form synthetic crude oil before being accepted by the refineries.
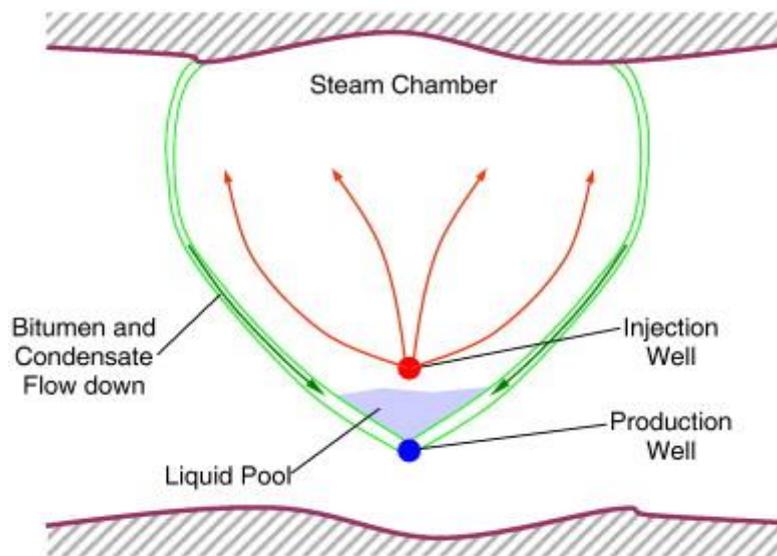
Figure 3.13: Steam chamber in SAGD process

Advantages

The SAGD process has significant advantages that arise from the fact that **horizontal drilling** is used. By definition horizontal wells are far more productive than the conventional vertical ones. Just to have an order of magnitude, the drilling of a horizontal well may cost 3 to 4 times more than a vertical well of the same length but the production obtained may be 10 times larger in the case of the horizontal well. This can be explained by the increased drainage areas of the horizontal wells that subsequently result in high ultimate Recovery Factors as presented in **Table 3.2**. The increased productivity of the horizontal wells results also in reduced surface disturbance

because it would need several more vertical wells for the exploitation of a specific field. When using a well pad with multiple horizontal wells, the surface disturbance may be reduced to less than 10% of the reservoir's area that is exploited. Furthermore, SAGD technique can have satisfactory results in low thickness oil formations where the rest of the Thermal EOR techniques are ineffective. Finally, it must be mentioned that most of the SAGD implementations do not require artificial lift facilities as the increased temperature and pressure mixture of fluids reach the surface facilities by their own energy.

Disadvantages

The main disadvantage of the method is that it is very energy intensive as large quantities of steam need to be generated. For every m^3 of bitumen produced on the surface, it is required to inject between 200 and 500 tones of steam with the needs to be bigger in low thickness reservoirs where the heat losses are greater. [14] For the above reason, efforts have been conducted to re inject the unexploited quantities of non condensable gas that are produced on the surface reducing by this way the quantities of steam required. This method is called **Steam And Gas Push** (SAGP) and it is still under development.

Field application

The SAGD technique as it has already mentioned, it is applied in highly viscous oil formations and in oil sands because of the high ultimate recovery factors that can be achieved in low mobility hydrocarbon accumulations. Another reason is because low mobility hydrocarbon accumulations are favorable for the creation of the steam chamber as steam channels are avoided. Also, formations with high vertical permeability are required so as the flow of the hydrocarbons towards the production well is not restrained.

According to a feasibility study conducted by *ICP* (Instituto Colombiano del Petroleo) the minimum requirements for a SAGD application to be efficient and economically viable are presented in **Table 3.3**[15]

Table 3.4: Minimal operational conditions for the implementation of SAGD technology

Steam Assisted Gravity Drainage	
Parameter	**Minimal operation conditions**
Depth	200 to 3700 ft
Rock Type	Sandstone
Thickness	>45 ft
Water Saturation	<40%
Specific Gravity	<20 °API

Permeability	>780 mD
Porosity	>20%

       A version of the Steam Assisted Gravity Drainage technique is illustrated in **Figure 3.14** where the horizontal steam injector has been replaced by a vertical one. As we can see this change was necessary to the particular reservoir because it is not enclosed by an impermeable cap rock and a base rock but there is a gas cap at the top and water at the bottom making the steam chamber of the original SAGD technique ineffective. It can be noticed that the steam is injected right below the gas cap. The steam and the condensed hot water mobilize the oil which flows downwards driven by the gravity to the producer well. This type of SAGD technique has been applied successfully with 11 pairs of wells in a sandstone reservoir 13 m thick in Tangleflags, in Canada.
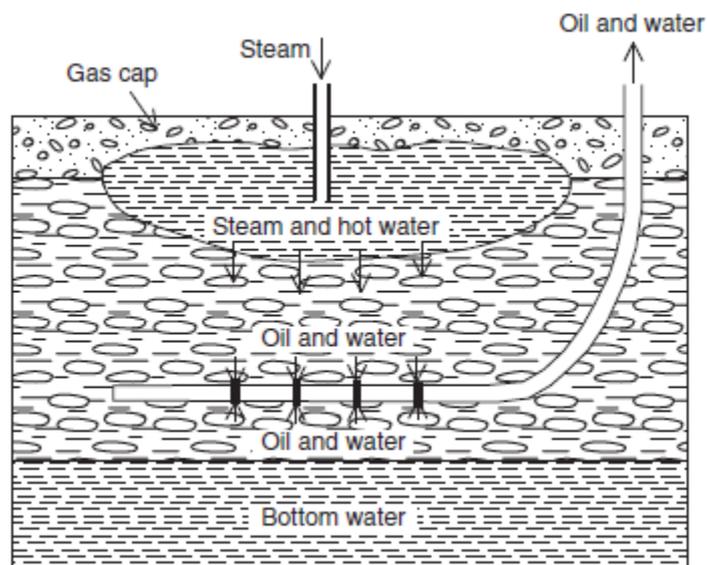
Figure 3.14: Steam Assisted Gravity Drainage

3.3 In Situ Combustion methods

The basic principle of all In Situ Combustion techniques is to achieve combustion in the pores of the hydrocarbon formation by burning part of the hydrocarbons (around 10% of OOIP) in order to produce the required heat, needed to lower the viscosity and subsequently increase the mobility of the unburnt part of the hydrocarbons. The oil displacement mechanisms of ISC techniques are **steam, hot water and gas drive**. The ISC techniques are able to achieve high levels of efficiency as there is no heat losses in surface facilities or along the well bore as it happens with hot fluid displacement methods. ISC techniques involve a multiple chemical reactions along with heat and mass transfer making this EOR method the most difficult to simulate making filed performance predictions quite unreliable.

In Situ Combustion methods include the two techniques mentioned below. In order to take advantage of the increased temperature of the reservoir after the combustion process, both of the techniques can have a **wet mode**, means that water is injected which is evaporated to create an additional steam drive. Otherwise, ISC techniques work on a **dry mode**.

1. **Forward Combustion** where the combustion front, propagates in the direction of the fluid flow meaning towards the production wells. It is the only commercial technique.

2. **Reverse Combustion** where the combustion front, propagates in the opposite direction of the fluid flow meaning towards the air injection wells. The effectiveness of this technique has not proved commercially viable.

In Situ Combustion techniques have been tested for the first in the USA oil fields during 1950s. Since then more than 162 ISC projects attempted economically viable production but the majority of them did not succeed. The economic efficiency of an ISC project can be described by two parameters and more specifically, the air/oil ratio (AOR) and the air injection pressure. For the same values of AOR lower injection pressure means better degree of efficiency. Nowadays, there are only four ISC projects that operate commercially as it is presented in **Table 3.4.** [16]

								Worldwide operational ISC projects								
Country	Field	Start Date	Injectors - Producers	Mode	Injection Pressure (psia)	AOR (Scf/bbl)	Oil Production (Bbl/day)	Expected Oil Recovery (%)
Romania	Suplacu	1971	111 - 736	Dry	150 - 200	14.000	9.000	52
India	Bahol	1997	30 -75	Wet	1.300 - 1.600	5.600	4.400	38
India	Santhal	1997	30 -105	Wet	1.200 - 1.500	5.600	4.000	36
USA	Bellevue	1970	15 - 90	Dry	60	15.000	320	60

Generally, combustion can be defined as a summation of exothermic chemical reactions, during which the chemical energy of the hydrocarbons is converted into thermal energy. As it is illustrated in **Figure 3.15** for the reactions of combustion to take place the following three substances are necessary in the appropriate proportion:

1. **Oxygen** that is provided by the air injectors. For the stoichiometric combustion of a specific quantity of fuel a corresponding quantity of oxygen (air) is required. In this case the quantity of air is called **stoichiometric air** and the ratio (λ) is equal to unity. The air requirements increase with the fuel availability. For an order of magnitude for a cubic meter of reservoir rock 200 to 400 st m^3 are required. [1]

2. **Heat** is necessary for the combustion reactions to start as the temperature of the fuel must be above a specific value that is defined by the type of the fuel. This specific temperature is called **ignition temperature**. During ISC techniques the heat released from the combustion reactions increase the temperature of the rocks near by and enables the combustion front to self propagate in the formation.

3. **Fuel** that is provided by the pyrolysis reactions of the crude oil that precede the combustion reactions. The compounds of crude oil means the Saturates, Aromatics, Resins and Asphltenes (SARA) go through pyrolysis process where the carbon rich solid residues means the **coke** feeds the exothermic reactions of combustion. More specifically, experiments have shown that coke formation is based mainly on the Asphaltenes and Resins whereas Aromatic fractions contribute only little and Saturate fractions have no contribution.
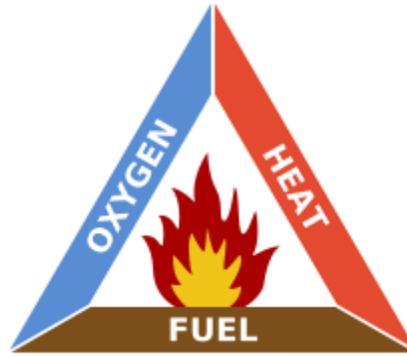
Figure 3.15: Fire triangle

As described above the formation of coke during pyrolysis is very crucial as it feeds the combustion reactions that follow. That means that the implementation of ISC techniques requires heavy oil fields of very low API gravity that have a big potential for coke production.

During In Situ Combustion Methods, hydrocarbons are going through the following temperature depending stages which can be overlapped and occur simultaneously:

Table 3.6: In situ combustion stages

In Situ Combustion progress	
Temperature	**Process**
40 - 270°C	Vaporization - LTO
270 -370°C	Distillation - LTO
370 - 560°C	Pyrolysis - Combustion
560 - 750°C	Combustion

During **vaporization** process the original water in place is evaporated and as a result a steam flood is generated which act like a very effective drive mechanism increasing the oil Recovery Factor. During **distillation** the volatile components of the hydrocarbons are separated. In this stage upgrading of the light oils occur.

Pyrolysis reactions occur in front of the combustion front. During pyrolysis the heavy oil fractions are cracked to form lighter oil components (gaseous and liquids) which are displaced by the gas flow and solid carbon rich residues (coke). Pyrolysis reactions are very important for the ISC process as they produce the coke that is the main fuel of the combustion process. Furthermore, when ISC is applied in heavy oil formations, pyrolysis reactions result in a degree of upgrading of the displaced oil increasing by this way the quality of the produced oil.

As **combustion**, must be considered the summation of the fast, exothermic crude oil - oxygen chemical reactions. More specifically, Saturates are oxidised in temperatures between 250°C - 300°C and Aromatics in the range between 300°C - 350°C. The resins are burnt between 300°C - 400°C and finally the combustion of Asphaltenes occur between 350°C - 500°C. [17] The oxidation – combustion reactions of the crude oil in the porous media can be distinguished in the following three temperature depending categories. Generally, the temperature of oxidation gets higher when fuel concentration (means residual oil saturation) is increasing and when reaction surface area gets bigger (usually in clays or sand fines).

- **Low Temperature Oxidation (LTO)** that occurs in the gas and liquid phases of the hydrocarbons in a temperature range between 250°C - 350°C. Generally LTO reactions are undesirable since oxidised hydrocarbons of increased polarity are formed. Increased polarity make hydrocarbons more viscous.

- **Middle Temperature Oxidation (MTO)** that occurs in the products of distillation and pyrolysis in a temperature range between 350°C - 500°C. After the completion of middle temperature oxidation heavy oil and solid residues are left in the solid matrix.

- **High Temperature Oxidation (HTO)** that occurs in the deposited residues (heavy oil and coke) in a temperature range between 500°C - 750°C.

3.3.1 Forward In Situ Combustion (Dry)
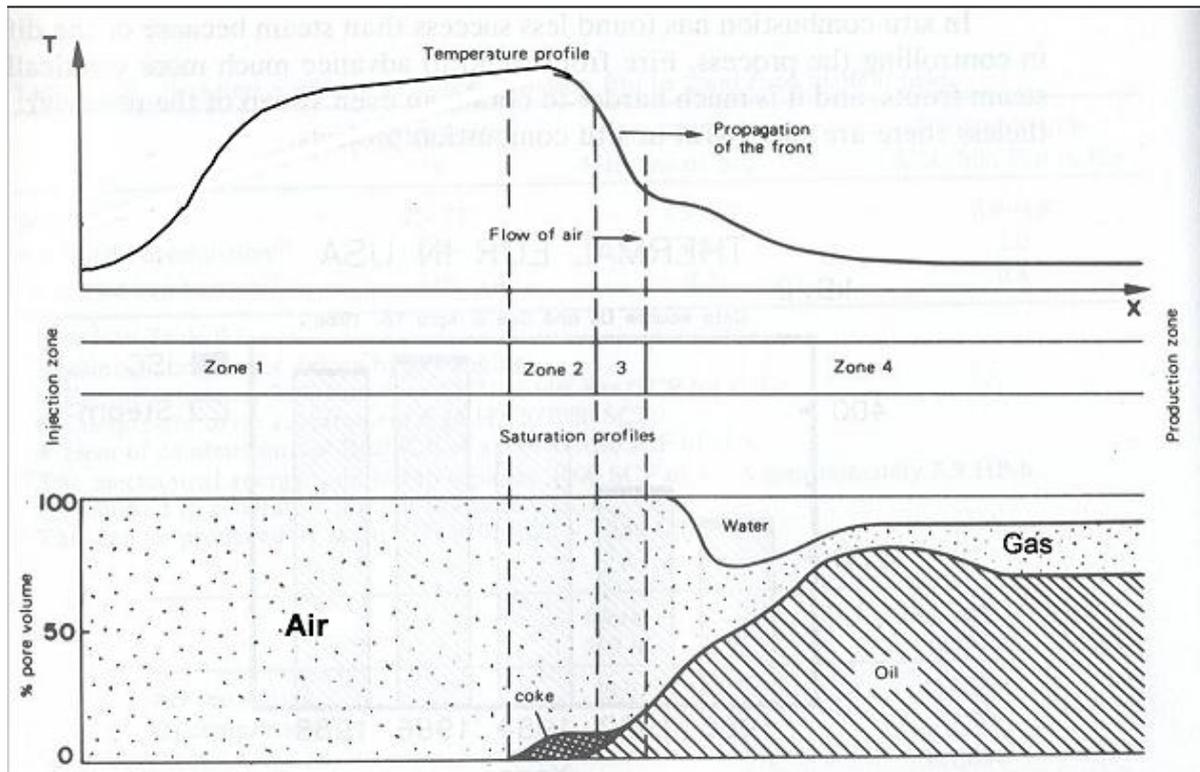
Figure 3.16: Temperature and Saturation profiles of Forward Combustion technique (Dry)

General description of the technique

As it has already mentioned, the basic characteristic of the forward combustion is that the propagation of the combustion front is at the same direction with the injected air. More specifically, the ignition occurs in the injection well and the combustion front follows the fluid flow towards the production well – from the left to the right in **Figure 3.16**. Another characteristic of the method as it can be seen from the Temperature profile is that behind the combustion front significant amounts of heat are stored in the reservoir rock. The injected air recovers some heat as it moves towards the combustion front this is why the temperature profile curve is decreasing as it approaches the injection well. The forward ISC process divides the reservoir in the following 4 zones as it is illustrated in **Figure 3.16**:

> **Zone 1**: In this area the combustion has already completed. It is characterized by high temperatures meaning high heat losses to the formations surrounding the reservoir. Also the pore volume is entirely covered by the injected combustion air.

> **Zone 2**: In this area the combustion reactions occur. The coke and part of the liquid and gaseous hydrocarbons are oxidized and the temperature reaches the maximum value.

Zone 3: In this area the pyrolysis reactions occur in lower temperatures. The heavy oil fractions that have been neither displaced nor vaporized are pyrolysed with no or very few quantities of oxygen present and they form the coke.

Zone 4: This low temperature area is fulfilled by the displaced oil, combustion gases (mainly CO_2 and CO), vapors, nitrogen and unburnt oxygen. Generally the viscosity and the specific gravity of the displaced oil are lower from the oil initially in place.

Advantages

As it has been already mentioned the only ISC technique that has been proven to be economical viable is the Forward ISC. That means that the advantages of ISC technique refer to the implementation of the Forward ISC.

The basic characteristic of the ISC techniques is that the produce the required heat in the reservoir so there is no need to transfer a hot fluid from the surface with the subsequent heat losses. This feature makes Forward ISC suitable for heavy oil reservoirs that are located in big depths where steam injection would have to deal with condensation problems and hot water flooding with high heat losses along the well bore. Furthermore, for the same reasons Forward ISC techniques could address successively to thin reservoirs where hot fluid displacement methods exhibit increased heat losses to the rock formations that surround the reservoir. From the above it can be deducted that Forward ISC technique is the most suitable EOR method for deep buried formations or formations of low thickness that otherwise could not have any exploitation potential. Furthermore, the increased thermal efficiency of ISC techniques result in decreased environmental impact - less emissions. The decreased operational facilities for the ISC methods result also in reduced surface footprint when compared with hot fluid displacement methods. Finally, a characteristic of the Forward ISC is that the produced oil has been partially upgraded and it is lighter than the initial oil in place.

Disadvantages

An important disadvantage that characterizes all the ISC techniques is the inadequate capability of controlling efficiently the progress of the procedure. Generally, it is harder to control the combustion front when compared with the steam front or the hot water front as in the first case the parameters of the chemical reactions like sufficient oxygen - coke quantities and the intense phenomena of heat transfer determine the progress of the technique. Another disadvantage is the decay of the production wells due to corrosion of the metallic surfaces that is enhanced from the combustion gases. Finally, ISC techniques always involve the risk of unexpected termination of the combustion process if the continuous air supply is disturbed due to a mechanical problem (compressors).

More specifically, Forward ISC exhibits a basic disadvantage as a method that has to do with the so called **liquid blocking phenomenon**. As it can be seen from the Temperature profile in **Figure 3.16** the reservoir's temperature around the production well remains at its original low values. That means that the oil zone around the production well maintains its high viscosity and stays immobile blocking by this way the fluids flow.

Field application

As it has already mentioned, the Forward ISC technique is the only EOR method that can be applied with success in deep or low thickness reservoirs. At this point it must be mentioned that for deeper ISC applications, the pressure of the injected air must be higher, increasing the cost of the operation. Generally the target oil formation of ISC techniques is heavy oil reservoirs which have the ability to provide the necessary coke quantities but also the potential of its implementation in depleted conventional oil reservoirs, in tar sand and in oil shales is under investigation. In **Table 3.6** the reservoir properties of the four operational ISC projects, are illustrated. [16]

As we can see from **Table 3.6** a common characteristic of these reservoirs is the relative high porosity. The high surface area in the porous media (high porosity) is absolutely necessary for the reactions of combustion and pyrolysis to take place.

Another basic requirement is that the reservoir must has an increased permeability that will enable the combustion front to be supplied with the necessary quantities of combustion air. In the case of Bellevue field in USA the low permeability results in low values of maximum air injection rates that have as a result a decreased oil production.

Also if the viscosity of oil takes high values then the liquid blocking phenomenon in the production wells acts negatively to the production oil rate. In the field of Suplacu, in Romania where the oil viscosity exhibits high values Cyclic Steam Stimulation is used permanently in the production wells.

Table 3.7: Reservoir properties of Worldwide operational ISC projects

Worldwide operational ISC projects							
Country	Field	Depth (ft)	Porosity (%)	Permeability (mD)	Oil Gravity (API)	Oil viscosity (cp)	Oil Saturation (%)
Romania	Suplacu	115 - 720	32	5.000 – 7.000	16	2000	85
India	Bahol	3.280	28	3.000 – 8.000	16	100 - 450	70
India	Santhal	3.280	28	3.000 – 5.000	18	50 -200	70
USA	Bellevue	400	32	650	19	676	73

3.3.2 Forward In Situ Combustion (Wet)
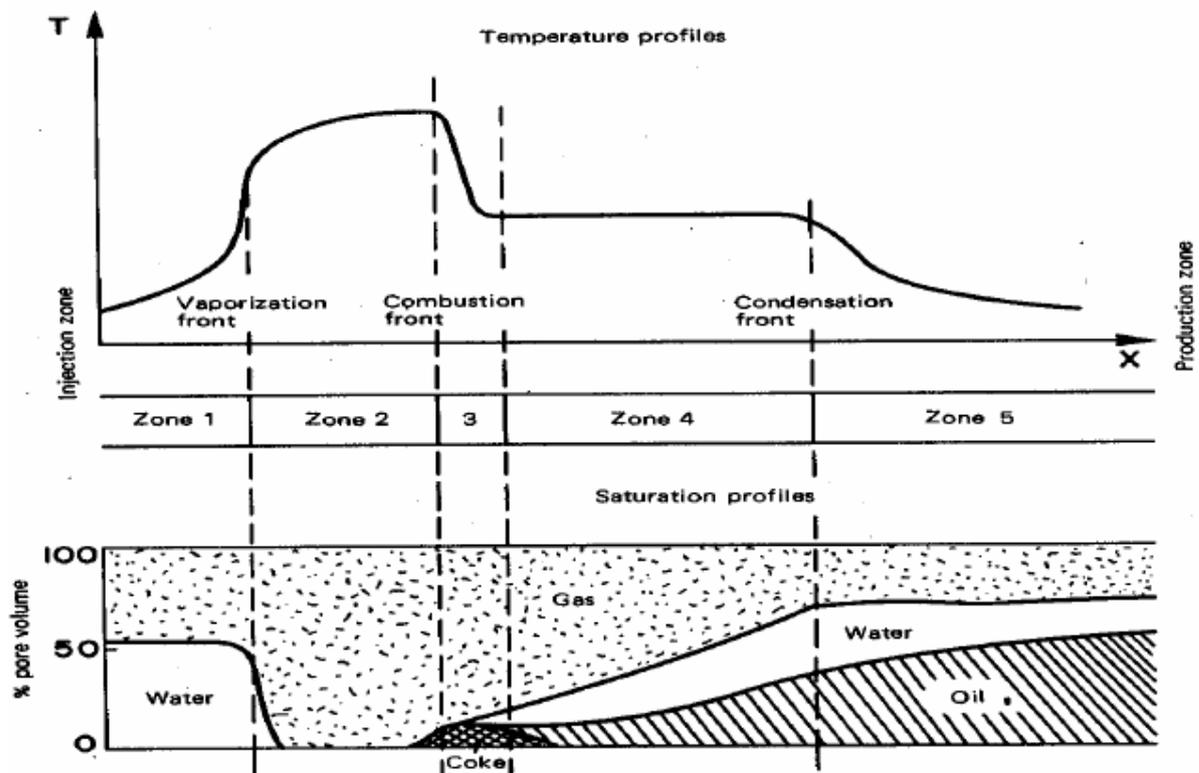
Figure 3.17: Temperature and Saturation profiles of Forward Combustion technique (Wet)

As it has already described, one basic characteristic of the Forward Dry ISC is that as long as the combustion front propagates, the heat released by the combustion is stored in the reservoir rock as it can be seen from the temperature profile of the Zone 1 in **Figure 3.16**. In order to make use the stored thermal energy and increase the effectiveness of the method, water is injected alternately (in reservoirs of low permeability) or simultaneously (in reservoirs of high permeability) with the combustion air stream. When water is injected along with the combustion air then the air stream gets an increased ability to recuperate heat (because of the high thermal capacity of water) and to transfer it from the already burnt area, to the colder downstream of the combustion zone. The purpose is to increase as much as possible the combustion temperature (by increasing the temperature of the combustion air) because by this way the efficiency of the combustion is increased. That means less fuel (oil) needed for the same amount of heat released. The result is that the oil production is accelerated and the oil recovery achieved by wet ISC is higher when compared with dry ISC.

Typical water / air ratios range between 0.001 – 0.004 m^3 / st m^3. [1] If the injected water quantities are less than the optimum ones then less heat is transferred and the high temperature zone is increasing. If the injected water quantities are more than the optimum ones then the high temperature zone is decreasing. In such a case if the vaporization front exceeds the combustion front the combustion temperature decreases radically and subsequently so as the combustion efficiency.

The forward wet ISC process divides the reservoir in the following 5 zones as it is illustrated in **Figure 3.17**:

Zone 1: In this area the combustion has already completed. The area near the injectors is characterized by relative low temperatures that are below the boiling point of water. As a result two phase flow occurs. At this point it must refer that significant quantities of the injected water finally increase the saturation of water (S_W) in the pores and never proceed to next zone.

Zone 2: As the two phase flow proceeds towards the combustion front, its temperature increases and at a point, it exceeds the boiling point of water. This point is called vaporization front and it is the boundary between zone 1 and zone 2. As we can see from temperature profile in **Figure 3.17** the temperature gradient is very high at the vaporization front due to the required heat of vaporization. In the zone 2 only the gaseous phase exists and the pores are saturated with the combustion air and vapours.

Zone 3: In this area the combustion reactions occur. The coke and part of the liquid and gaseous hydrocarbons are oxidized and the temperature reaches the maximum value.

Zone 4: In this area the water quantities that were injected and those that are produced by the combustion process, go through successive condensation – vaporization till the condensation front where the temperature is below water's boiling point. Also in this area quantities of light and intermediate hydrocarbons are vaporized and incorporated to the flow stream.

Zone 5: This area is characterized by low temperatures that approach the initial reservoir's temperature. As it can be seen from the saturation profile in **Figure 3.17** a biggest percentage of the pore volume is captured either by water or by oil meaning that the pressure is decrease when compared with the pressure in zone 4 where the gas quantities cover the biggest part of the pore volume.

If we compare the temperature profiles of dry ISC and wet ISC we could see that water injection resulted in reduction of the extent of the high temperature zone and in lengthening of the condensation zone (steam plateau). Reduction of the extent of the high temperature zone means less heat losses to the surround rock formation. The lengthening of the steam plateau results in more efficient oil displacement which results in increased oil recovery. It could be mentioned that the wet ISC can face more effectively the increase heat losses of the thin reservoirs.

In conclusion, wet ISC achieves higher displacement efficiency meaning more oil is produced for the same reservoir conditions when compared with dry ISC. If water quantities are available wet ISC should be preferred. However, in inclined reservoirs the movement of water may be restricted by the gravity and in these occasions dry ISC should be selected.

3.3.3 Toe to Heel Air Injection (THAI)
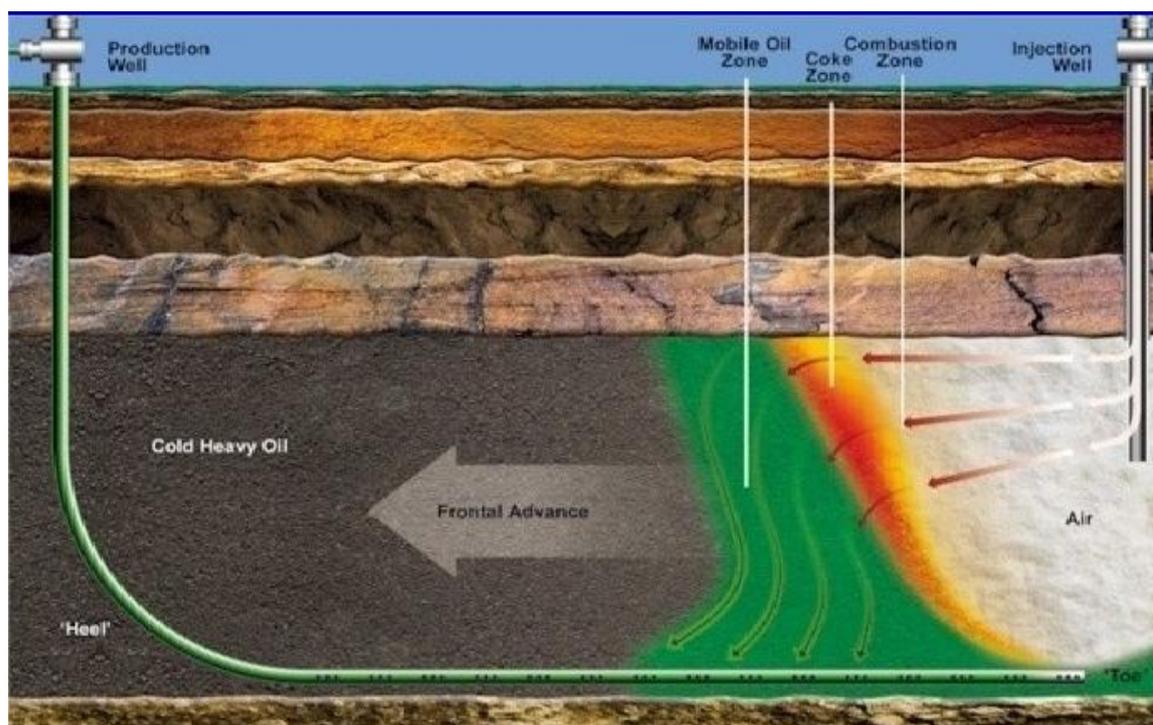
Figure 3.18: Toe to Heel Air Injection (THAI)

General description of the technique

Toe to Heel Air Injection (THAI) is technique that integrates advanced horizontal drilling in the Forward In Situ Combustion process increasing by this way the potential ultimate Recovery Factor in heavy oil and tar sands reservoirs exploitation. The basic characteristic of THAI method is the use of horizontal wells as producers instead of vertical wells that are used in conventional in situ combustion processes. THAI is the most representative implementation of the Short Distance Oil Displacement (SDOD) processes where oil is driven to the producer via a short flow path without going through cold areas of the reservoir. THAI technique could be characterised as a very promising EOR method as it manages to maintain high injection flux of the combustion air and high temperatures in the combustion zone. These two parameters are very crucial for the successful implementation of an ISC project. The THAI technique was tested in a real field for the first time in 2005 at Athabasca tar sands, in Alberta, in Canada.

The basic principle of the technique is illustrated in **Figure 3.18** and involves the propagation of the combustion front along the penetrated horizontal producer, from the *toe* to the *heel* position. As it can be seen from the illustration, the combustion air is injected from the top of the reservoir whereas the produced is placed along the bottom of the reservoir. This is a basic characteristic of the technique as the main drive mechanism of the mobilized hydrocarbons is the gravity drainage. The THAI process is divided in the following 5 zones as it is illustrated in **Figure 3.18**:

Burn out zone: In this area the combustion has already completed. A basic characteristic of this area is the increased permeability that comes as a result of the high sweep efficiency of the THAI process. By this way the combustion zone is more accessible to the injected combustion air.

Combustion zone: The combustion zone of the THAI process can be characterized by the high sweep efficiency of the combustion front and by the fact that the undesirable low temperature oxidation (LTO) is minimized. The temperatures are relative high ranging between 450 -650°C as the cold area of the reservoir remains sealed.The temperature of the combustion front is controlled by the air injection rate. [18]

Pyrolysis zone: In this area the pyrolysis reactions occur and the heavy oil fractions that have been neither displaced nor vaporized are pyrolysed and quantities of coke are formed that will feed the combustion reactions.

Mobile oil zone: A characteristic feature of THAI process is the narrow mobile oil zone that is formed in front of the pyrolysis zone. In mobile oil zone the flue gases, the mobilized hydrocarbons and the vapors, move from top of the formation to the bottom towards the producer well under gravity drainage. The creation of the narrow mobile oil zone makes the combustion process to operate efficiently and in stabilized manner. As oil is being displaced in the mobile oil zone is being upgraded at the same time via thermal cracking.

Cold oil zone: In this area the reservoir temperature is near the initial one and the hydrocarbons maintain their high viscosity and their immobile behaviour. In fact, the cold oil zone prevents any bypassing of the fluids and guides them towards the exposed sections of the production well allowing them to have a very short flow path. This makes the combustion front to propagate in a stabilised way. The result is an increased sweep efficiency of the process as most of the target area of the reservoir is covered by the combustion front. Further more, the short flow path of the mobilised hydrocarbons makes the process less sensitive to heterogeneities of the reservoir formation.

Concerning the well configurations several variations exist. The producer well is always an horizontal well but the injector can be vertical or horizontal depending on the reservoir's permeabilities (vertical and horizontal). Generally, reservoir simulations have proved that a horizontal injector is able to provide more uniform distribution of the injected combustion air. More specifically, the combination of one horizontal injector (blue line) with two horizontal producers (green lines) as it is illustrated in **Figure 3.19** proved to be the best well configuration. [19]
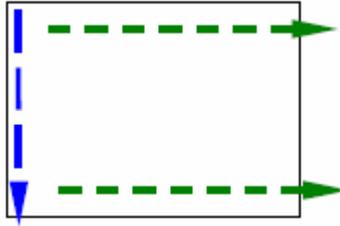
Figure 3.19: Best injector - producer well configuration in THAI technique

Advantages

The most significant advantage of the THAI process is the high efficiency that demonstrates in heavy oil recovery. Simulation studies have proved that THAI process can achieve very high ultimate recovery factor that could reach 85% of the OOIP. [20]

An important advantage of THAI method is that the high level of oil upgrading that is achieved in the pyrolysis zone is preserved as the flow path of the mobilised oil is very sort. In conventional in situ combustion techniques the mobilised oil has to go through the cold oil zone which lowers the upgrading quality. Experimental studies on Tar Sands samples proved that the oil produced after THAI process had an increased API gravity of 8 points. [21]

One more advantage that results from the sort flow path of the mobilised hydrocarbons that is imposed by the immobile cold region is that the combustion air flow is restricted to bypass the combustion area due to channelling, decreasing by this way the unburnt quantities of oxygen. This means that for the combustion process to occur THAI method requires less quantities of compressed air for the same fuel to burn. The resulting air/oil ratio (AOR) is decreased (almost halved) and that increases the efficiency of the THAI process.

Furthermore, the short distance between the combustion front and the production well that characterizes the THAI process does not require prior steam injection or heating in order to create communication between the injector and the producer as it happens in conventional ISC techniques.

Finally, due to the fact that the combustion front moves along the production well from the *toe* point to the *heel* point it is very easy to locate the progress of the process and subsequently to control it more accurately. Moreover, this linear, controlled propagation of the combustion front enables the use of decreased numbers of wells during a commercial line drive operation because the wells that operate as producers they are converted to injectors.

Field application

The THAI technique gives the potential for an economically viable exploitation of heavy oil and tar sands accumulations with a decreased environmental impact.

A very promising variation of THAI method is the so called **THAI – CAPRI** technique (Catalytic upgrading process In situ) that promotes in situ upgrading of oil using a catalytic layer incorporated to the horizontal well - producer. The THAI – CAPRI technique has the potential to upgrade the heavy crude oil quantities to light oil of commercial value, in situ without the installation of further surface upgrading facilities. The upgrading of heavy crude oil occurs via carbon rejection reactions and the addition of hydrogen at the surface of the catalyst. The THAI – CAPRI technique requires temperatures ranging between $400 - 600$ °C in order for the catalytic reactions to take place. More specifically, experimental studies on tar sands proved that THAI technique was able to decrease the specific gravity of the heavy oil by 10 °API. When the THAI – CAPRI technique was tested, further decrease in the range of 4 - 7 °API was achieved by using Ni-Mo and Co-Mo hydrodesulphurization catalysts. [22] However, issues like short catalyst lifetime and the possibility of catalyst bed plugging make the process to be in experimental phase.

3.3.4 Reverse Combustion
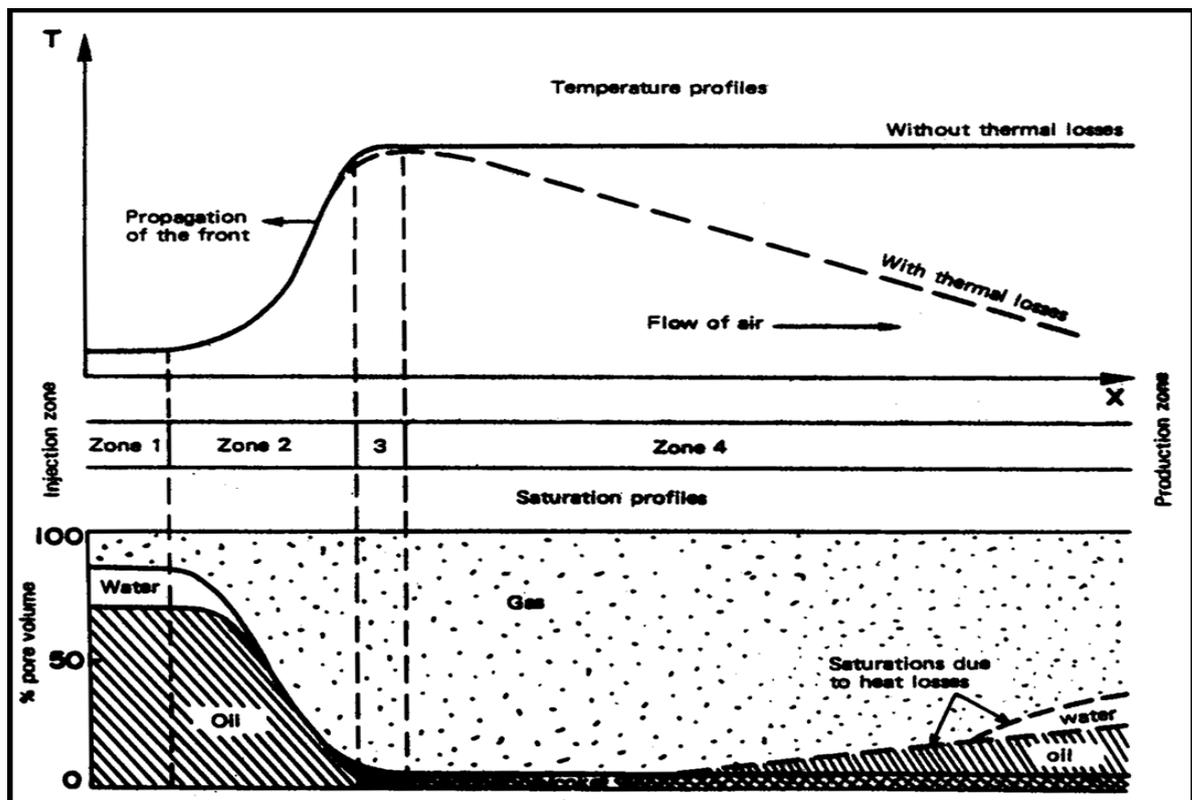
Figure 3.20: Temperature and Saturation profiles of Reverse Combustion

General description of the technique

The principle of Reverse ISC techniques whether is dry or wet, involves the propagation of the combustion front in the opposite direction to the injected air flow. The combustion is initiated at the production well which during the ignition process, acts like an air injector. After a short period of time, when the combustion front has propagated for a short distance, air is injected only by the injector, making the combustion front to move towards the injector and the oil towards the producer. The Reverse ISC process divides the reservoir in the following 4 zones as it is illustrated in **Figure 3.20**:

Zone 1: The properties of the area near the injectors are found close to the initial condition of the reservoir rock. Low temperature profile and increase oil saturation (S_o). However due to the combustion air influx, it is possible that LTO occur in a small extent if the oil is easily oxidizable.

Zone 2: In this area vaporization – oil distillation phenomena occur. As it can be seen from the temperature profile, the temperature increases as a result of heat transfer by conduction, from the combustion zone that follows. From the saturation profile it can be seen that the connate water quantities are vaporized. Concerning the liquid hydrocarbons a part of them is oxidized, another part is gone to the gaseous phase and finally some hydrocarbon fractions, form a solid residue, the coke after thermal cracking.

Zone 3: In this are the majority of the combustion reactions occur and the temperature reaches its maximum value.

Zone 4: This is the burn out zone. At the beginning of the zone there are only the combustion gases, unburnt hydrocarbons in gaseous phase and the unburnt quantities of the solid coke. Because of the heat losses, the temperature of th burn out zone is decreasing as we move away from th combustion front. This results in the condensation of the vapours and the unburnt part of the hydrocarbons that flow in the liquid phase towards the production well. As we can see from the saturation profile, significant quantities of coke remain unburnt in the reservoir's pores.

Advantages

Reverse combustion technique has no chances to be commercialized, however it exhibits some positive features. Despite the low Recovery Factors achieved, the oil that is produced goes through significant upgrading, the API gravity is increased and it can be characterized as oil of good quality. Also, the technique involves the flow of the gaseous and the condensed hydrocarbons through the burn out zone which means that there is the minimum possible flow resistance. There are no liquid blocking issues that the forward combustion techniques have to deal with.

Disadvantages

The basic disadvantage of the method is the low values of the resulted Recovery Factor that have little room for improvement. This is attributed to the design of the technique. As it has already explained the light and intermediate fraction of the hydrocarbons that have gone into the gaseous phase, go through the combustion front, where a significant part of them is burnt reducing the amount of oil that can be recovered. Also, as it has already mentioned significant quantities of the coke remain unburnt in the reservoir's pores. That means that during thermal cracking of the oil more fuel (coke) has produced than it was necessary for the feeding of the combustion front. The relative large amounts of coke that are formed from a specific quantity of oil actually decrease the potential for displaceable oil production..

Furthermore, because of the heat losses in the burn out zone the temperature is decreasing and a significant part of the gaseous hydrocarbons condensate increasing the oil saturation in the pore volume and decreasing the recoverable quantities. From the above it can be conducted that the reverse combustion technique will always result in lower Recovery Factors for the same reservoir conditions, when compared with the forward combustion techniques.

Finally, another important disadvantage of the method is the increased likelihood of spontaneous ignition near the injection well. This possibility increases as the temperature of the reservoir and the reactivity of the crude oil are increased. If spontaneous ignition occurs then the oxygen of the injected air is consumed and the combustion front cannot be maintained. Another important issue that makes the process difficult to control is the supply of the combustion front with the optimum quantities of oxygen (especially if the wells are far from each other) as the combustion air has to go through the cold oil zone of low permeability before it reaches the combustion front.

Field application

The small effectiveness and the lack of adequate control are the basic characteristics of the Reverse ISC that does not allow its implementation in the real fields. However, the Reverse ISC seems to be more advantageous in very heavy oil fields or in tar sands where the forward ISC cannot be effective due to the completely lack of mobility that characterizes the original oil in place. From the temperature profiles we can see that the temperature near the production well in the Reverse ISC is higher when compared with the corresponding temperature of the Forward ISC enhancing by this way the mobility of the viscous hydrocarbons.

3.4 Electro - EOR methods

The basic principle of all Electro - EOR methods is to make electric currents traverse the target oil formation so as to increase its energy. The electric current when is crossing the reservoir, manages to increase the temperature of the surrounding rock formations or in some applications to create vibrations in the hydrocarbon molecules. In other words, the electric energy of the current, changes form and add thermal energy or kinetic energy (vibrations) in the hydrocarbon molecules which result in the desirable increase of the oil mobility. Based on the frequency of the electrical current the electro – EOR methods can be distinguished in the following three categories. Generally, as the conductivity of the rock formation is decreasing, means specially the water saturation S_w, higher frequencies demonstrate greater efficiency:

1. **Resistive heating** (low frequency current at 60Hz)

2. **Inductive heating** (medium frequency current less than 300KHz)

3. **Microwave heating** (high frequency current more than 300MHz)

Advantages and Disadvantages of Electro - EOR methods

The Electro EOR methods do not depend so much in the properties of the target reservoir. In contrast, the effectiveness of the Thermal methods that were described above, depend at a big extent, to the depth, the uniformity and the rheological properties of the target reservoir since a fluid is injected (hot water, steam or combustion air). Similarly, the previously mentioned Thermal EOR methods rely on heat transfer phenomena via conduction and convection that depend largely on the thermal conductivity of the target reservoir and require much more time for the outcome desirable result means the increase of the hydrocarbons' temperature.

Furthermore, the control of Electro EOR methods is much easier. The energy that needs to be transferred to the reservoir is very easily adjustable and more focused according to the specific spatial and temporal requirements minimizing by this way the heat losses and making them suitable for very thin pay zones. In other, more simplified words, is much easier to control and adjust the flux of the electric current in the reservoir rock, when compared with the flux of the large quantities of fluids that the other Thermal EOR methods require. Finally, the Electric – EOR have a significant lower environmental footprint and because of the fact that their implementation does not require extensive equipment and infrastructure and no waste material is produced, they seem to be very promising for off shore applications.

Electricity constitutes the highest quality of energy, and it is considered to be an expensive, not economical viable way to enhance the oil recovery of a whole oil field. However, techno – economic studies have proved the great benefits and the commercial viability of the electrical wellbore stimulation techniques as significant removal of the near wellbore skin effects is achieved along with improvement in the pumping efficiency.[23] Summarily, E – EOR methods are more suitable for heating a specific part of the reservoir.

3.4.1 Resistive heating
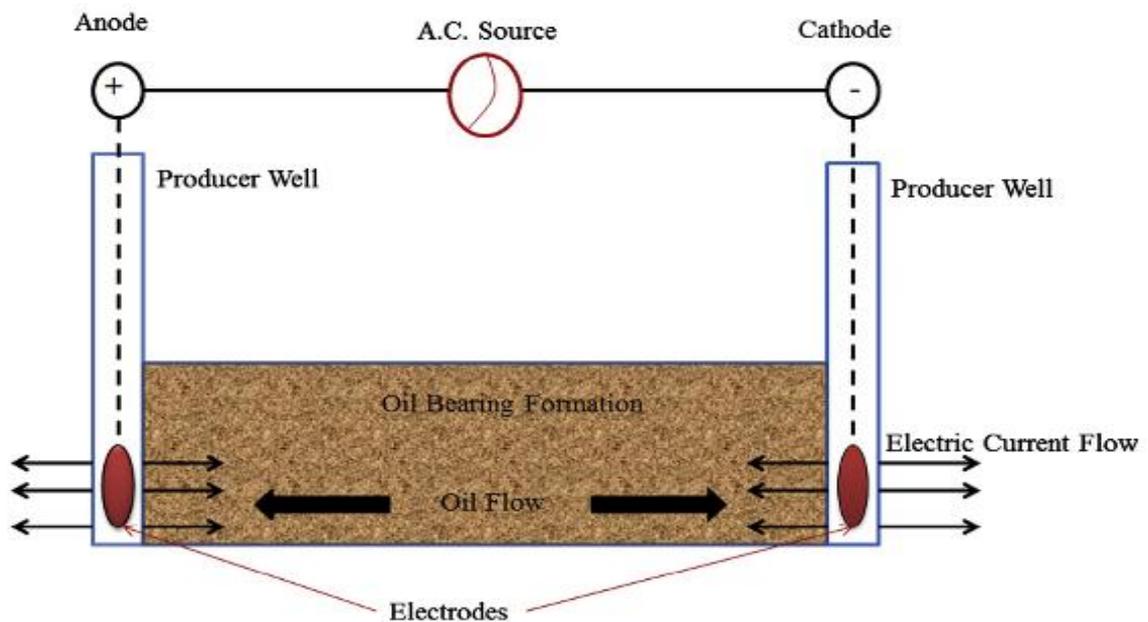
Figure 3.21: Resistive heating

General description of the technique

The basic principle of the Resistive heating is to apply a voltage difference between two points of the reservoir and make the electric current cross the reservoir formation. In order to apply the voltage difference in the reservoir two electrodes are needed an anode (+) and a cathode (-) and for this reason the production wells are used as it is illustrated in **Figure 3.21**. When an electric current traverses a conductor, heat is produced due to power dissipation. In other words, the electric energy is converted in heat energy which is given by the Joule's Law. This is why this type of heating is also called Ohmic or Joule heating.

Joule's Law: $\mathbf{Q = I^2{*}R{*}t}$

Where **Q** is the produced heat, **I** is the intensity of current, **R** is the electrical resistance of the reservoir rock and **t** is the time the current is allowed to flow.

The electrical resistance **R** of the rock formation is given by the so called Archie equation. Depending on the type of the rock formation many variations of Archie's equation exist. Below a version for sandstone reservoirs is presented.

Archie's equation: $\mathbf{R = (0{,}62{*}R_w) / (\Phi^{2,15} * S^2_w)}$

Where **R** is the electrical resistance of the reservoir rock, **Φ** is the porosity of the reservoir, $\mathbf{S_w}$ is the average water saturation of the reservoir rock and $\mathbf{R_w}$ is the electrical resistance of the brine. From the above equation we see that reservoirs with increased values of porosity and water saturation demonstrate relative low values of electrical resistivity. As it has already demonstrated by Archie's equation, the connate water increases significantly the conductivity of the reservoir and is very crucial for the transit of the current and subsequently, the heating of the reservoir. If the reservoir's temperature exceeds the boiling point of water, then the electrical resistance of the

reservoir increases so much that the method becomes not functional. A possible solution is suggested to be the combined resistive heating with the injection of a resistive fluid, like water. Another issue that this method involves is that the possibility of the electrodes to be negatively affected by corrosion.

Field application

A variation of the technique that enables the operations to be independent of the imposing increase of temperature (that may exceed the boiling point of the connate water) and the properties of the reservoir, is the use of heater wires. These wires consist of a mineral core (conductor) that is insulated with graphite or a polymer material and they can be 1.000m long making them suitable for heating horizontal reservoirs of low thickness. An advantage of this method is that the temperature increase of the reservoir can be easily regulated.

Shell company, has introduced such a technique that targets oil shale formations and several field experiments have been conducted in Colorado, USA. This technology has not yet been developed enough to be used extensively in a commercial basis but in general it can be characterized as very promising if issues of ground water contamination are solved satisfactorily. The Shell's Resistive technique is illustrated in **Figure 3.22** and involves three phases:

1. **Freeze wall phase** where an underground frozen barrier is established. In order to prevent groundwater from entering in the extraction zone or hydrocarbons from leaving away, a refrigerated fluid (like ammonia) is injected along the perimeter of the extraction zone to create a frozen wall and to insulate it.

2. **Heating phase** where the vertical electric heaters that are placed in the oil shale formation, heat the surrounding rock till it reaches a temperature near $340 - 400$ °C. At these temperatures the kerogen goes through thermal cracking and crude oil is released from oil shales. The heating phase may last two to three years.

3. **Production phase** where the oil is pumped to the surface using conventional producers that are spread in the heated zone.
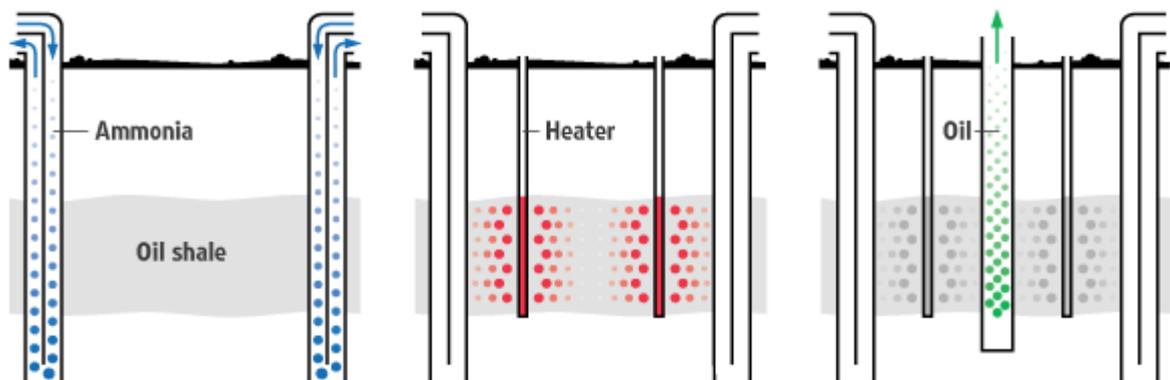
Figure 3.22: Shell's In situ Conversion Process (ICP)

2.4.2 Inductive heating
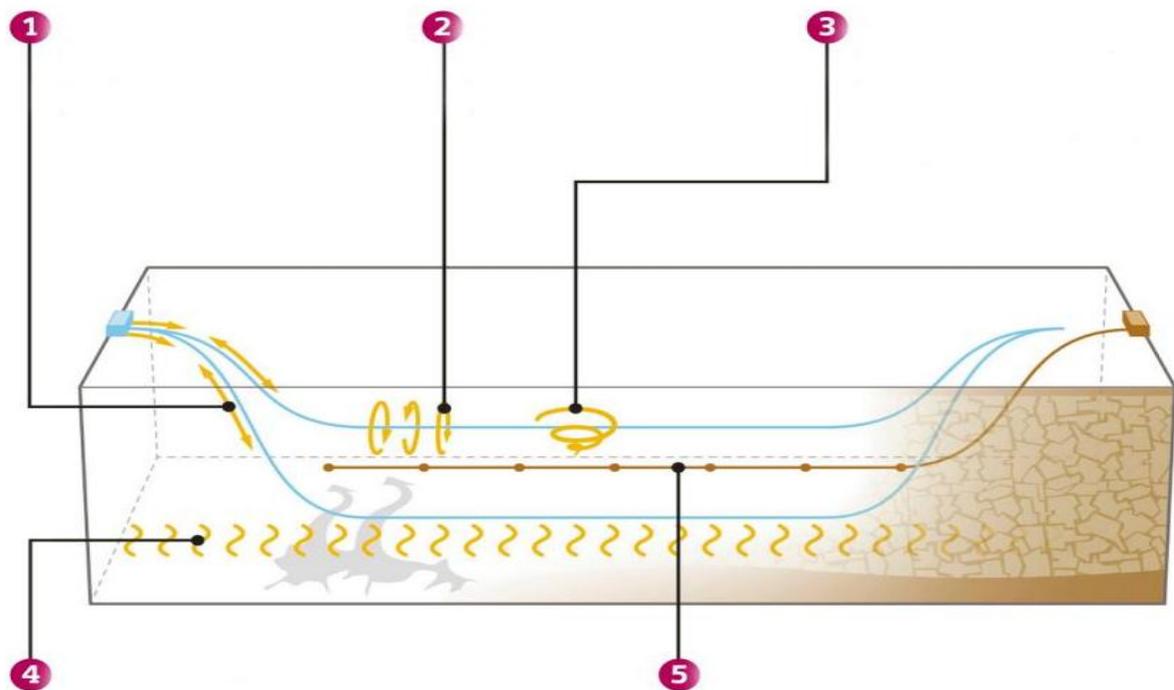
General description of the technique

Generally speaking, inductive heating could be defined as the procedure where an electrically conductive material is heated by electromagnetic induction. In every electrically conductive material which found in the area of a variable electromagnetic field, Eddy and displacement currents are produced.

In **Figure 3.23** an implementation of the electromagnetic induction technology is illustrated that involves the following procedures:

1. The blue lines that cross the reservoir rock are induction cables that can be 1000m long. An inverter provides the induction cables with alternating voltage and subsequently alternating currents are formed.

2. The alternating currents that cross the induction cables create an electromagnetic field.

3. The electromagnetic field creates the Eddy currents whose resistive losses as they spread into the rock formation, produce heat. The reservoir must a have a certain amount of electric conductivity means S_w for the success of the technique.

4. As the temperature of the rock that surrounds the cables is increasing, the mobility of the oil is increased.

5. At the same level with the induction cables a horizontal production well is drilled towards which the mobilized oil flows.

The electromagnetic induction heating technology that was presented in **Figure 3.23** is more applicable to shallow reservoirs. Nowadays maximum depths of 400m have been achieved by Siemens and Wintershall Holding GmbH partnership. As it can be seen in order to install the induction cables the *river crossing drilling* technique is used. This technique involves the creation of a bore at an angle $20 - 30$ degrees until the target depth is reached after which the bore and subsequently the installed induction cables become horizontal.

Field application

A variation of electromagnetic induction heating is the so called down hole induction heater that its principle of function is based on a common Current Transformer that is illustrated in **Figure 3.24.** In a Current Transformer an alternating current is produced in the secondary winding by induction when an altering current is imposed to the primary winding that can be a conductor.
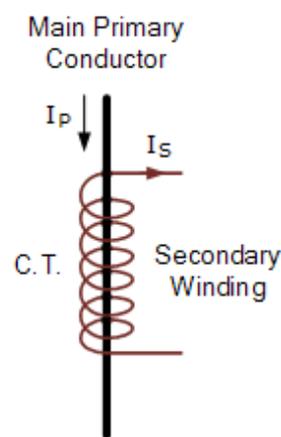
Figure 3.24: Current transformer

In **Figure 3.25** a section of a downhole induction heater is illustrated that includes the following parts: the casing (1), a terminal (2), an induction coil (3), cores made by ferrite (4), pole pieces (5), space filled from non magnetic material (6), the upper attachment point made of stainless steel (7), temperature sensor (8) a sealed instrument compartment (9) and the connector which is from stainless steel and is connected with the power network (10).

As it is shown from **Figure 3.25** the primary winding (conductor) of the current transformer is placed inside the casing at the bottom of the wellbore and it is the part (3) - the induction coil. When medium frequency alternating current is imposed at the induction coils then an altering current is formed to the section of the casing that is adjacent to the induction coils, means these parts act as a secondary winding of the current transformer. The alternating current that is formed via induction, heat the steel of the casing due to the ohmic resistance and the heat is transferred to the surrounding formation – production zone via conduction. By increasing the frequency of the alternating current of the primary winding the rate of heating is proportionally increased

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till a point where the electrical transmission losses and the capital cost of equipment make the further increase unprofitable.
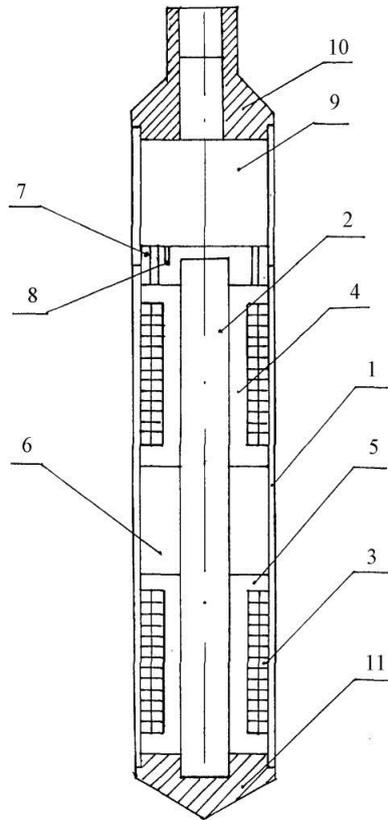
Figure 3.25: Downhole Induction heater

Induction heaters are mostly installed in vertical wells but they can be found also in horizontal wells where they can be combined with the SAGD technique. The induction coils configuration (means the induction tool) can move in the wellbore and placed where heating is required. Generally, the heated radius of the induction heater is relative short, around 2m when compared with the heated radius of the resistive heating method which varies between 5 to 10 m around the electrodes. When induction heating or resistive heating are used to stimulate a well then significant removal of the near wellbore skin effects is achieved along with improvement in the pumping efficiency.

3.4.3 Microwave heating
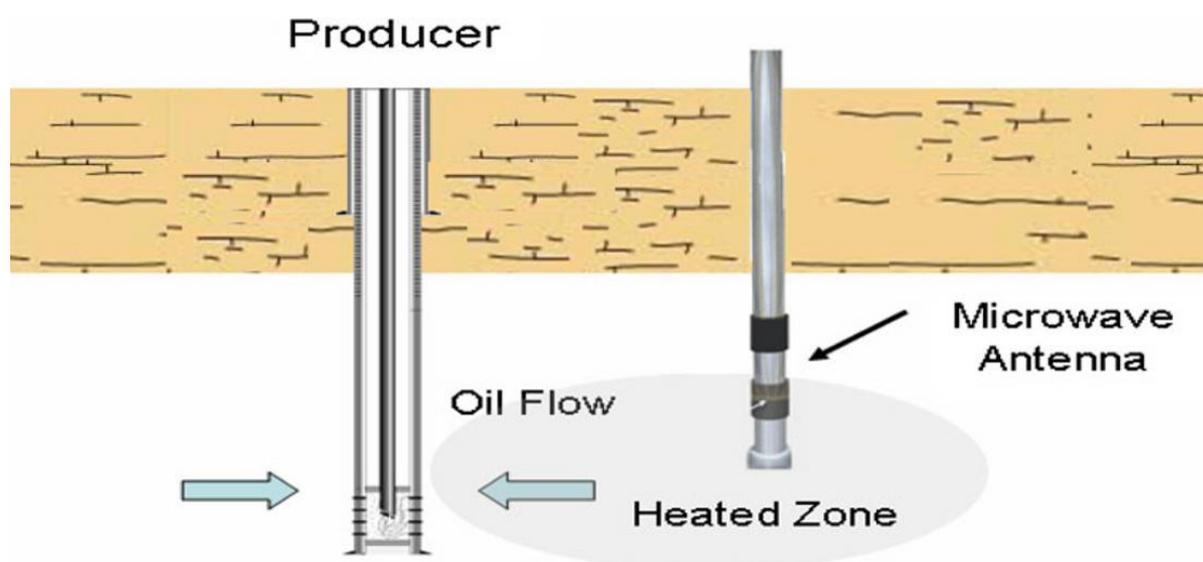
Figure 3.26: Microwave heating

General description of the technique

The basic principle of the Microwave heating is to transmit microwaves via an antenna that is situated in a drilled hole close to the production well and to heat the surrounding hydrocarbons as a result of the dielectric heating effect. Generally, microwaves can be **transmitted**, **absorbed** or **reflected** by a material where heating process is maximized mainly when absorbed by a material. According to the dielectric heating effect, heat is produced as a result of the interaction between the microwaves and the polar molecules of the exposed material. As a consequence, in the majority of applications, microwaves heat the exposed materials as they are absorbed by the incorporated, high polarity water molecules.

During microwave exposure, the polar molecules tend to align themselves and they result in a rotational movement that is proportional to the frequency of the microwaves. The frictions of the vibrating polar molecules generate the desirable heat. The more increased is the water saturation S_w of the formation the more effective is the microwave heating process. Generally, crude oil as a material has a very low microwave absorption ability. Although never tested in the real fields, laboratory tests have proved that the injection of powdered microwave receptors (like chlorides, metallic oxides and activated carbon) during fracturing operation can improve drastically the microwave oil absorption. [24] Also, hydrocarbons mixed with sand demonstrate good microwave absorption ability. The effectiveness of microwave heating depends on parameters like the design of the microwave source, the reservoir temperature, the frequency of the transmitted microwaves

From all the above, it is clear that microwave heating is a faster process when compared with the previous Electric EOR methods as it does not involve heat transfer via the relative slow mechanisms of convection or conduction where physical contact is required. As a disadvantage of the method, could be referred the decreased penetration depth of the microwaves that limits the activity radius. The higher is the

microwave frequency, the more is the attenuation of the microwaves and the less is the resulted penetration depth. This issue could possibly be encountered by the use of a microwave cable. Just to have an order of magnitude, laboratory experiments on tar sands have shown that the penetration depth is maximized at 15 meters when a frequency of 2450 MHz is applied. [25] Moreover, microwaves are propagated in line of sight and any possible obstacles could prevent them from reaching the target area. Finally, a system for the cooling of the microwave source is required to be installed to prevent its damage from overheating.

Field application

Generally, microwave heating demonstrates the biggest potential for commercial implementation when compared with the rest of the Electric EOR and this is attributed to the effective conversion of electrical energy to thermal energy that dielectric heating process offers. Simulations studies have proved that downhole dielectric heating can accelerate significantly the oil recovery process for medium crude oil (24°API), heavy oil (11°API) and extra heavy oil (7.7 °API) as well. More specifically, for the case of the heavy oil (11°API) the simulations indicated that the ratio between the energy extracted (additional crude oil) to the energy added to the reservoir (electricity) were ranging from 8 to 20 proving the effectiveness of the well stimulation method. [26]

Other simulation studies indicate that the combination of microwave heating with horizontal drilling show great potential for commercial implementation. The result of the combination of these two techniques is the Microwave Assisted Gravity Drainage (MWAGD). A version of MWAGD includes a horizontal producer well and several vertical wells with downhole microwave antennas installed. A second version of MWAGD technique that is illustrated in **Figure 3.27** involves two horizontal wells where the producer is at the bottom and the microwave antennas installed are installed in the upper well. The microwave antennas range allows the two horizontal wells to be placed at 15 meters distance between each other. The heating range of the MWAGD is increased when compared with the conventional SAGD's where the corresponding distance was only 5 meters. [24]
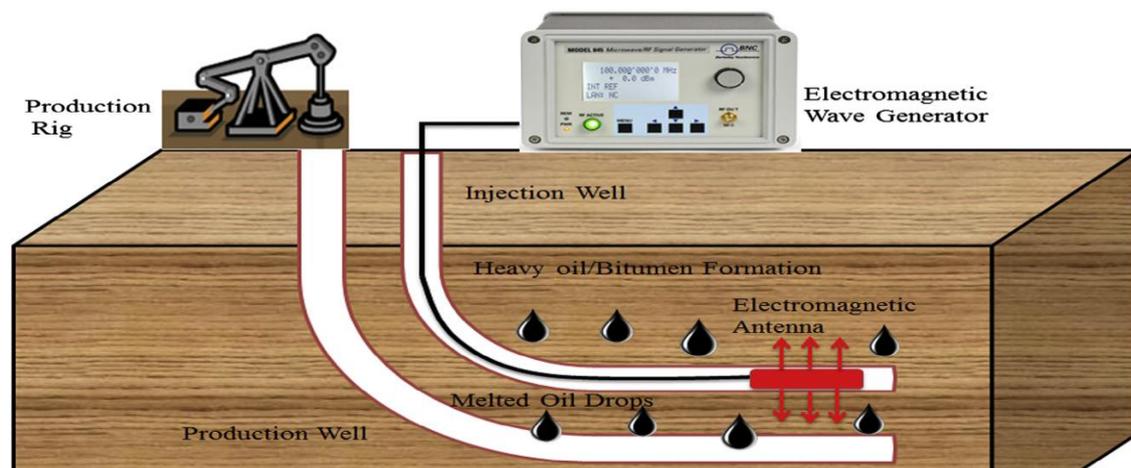
Figure 3.27: Microwave Assisted Gravity Drainage

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http://link.springer.com/article/10.1007/s13202-013-0096-4

[23] Journal of Canadian Petroleum Technology‐ In Situ Electromagnetic Heating for Hydrocarbon Recovery and Environmental Remediation

https://www.environmental-expert.com/articles/in-situ-electromagnetic-heating-for-hydrocarbon-recovery-and-environmental-remediation-238445

[24]Journal of petroleum engineering - Electromagnetic Heating of Heavy Oil and Bitumen: A Review of Experimental Studies and Field Applications

https://www.hindawi.com/journals/jpe/2013/476519/

[25] SPE – 78982 – MS : Upgrading a Heavy Oil Using Variable Frequency MicrowaveEnergy

[26] SPE – 78980 – MS : Opportunities of downhole dielectric heating in Venezuela: Three case studies involving medium, heavy and extra heavy crude oil reservoirs.

[27] EOR Screening Critiria Revisited – Part 1: Introduction to screening criteria and enhanced recovery field projects

http://www.prrc.nmt.edu/groups/res-sweep/media/pdf/publications/Replacement%20Pubs/EOR%20Screening%20Criteria%20RevisitedPart%201.pdf

Chapter 4 EOR – Miscible Flooding

4.1 Introduction

Fluid displacement techniques are distinguished in two main categories:

- **Immiscible displacement** where the displacing and the displaced fluid cannot be mixed together. We can have a single phase flow (like waterflooding) or a two phase flow (like natural gas injection) but at every circumstance the displacing and displaced fluid remain segregated. Immiscible displacement is used during secondary production.

- **Miscible displacement** where the displacing and the displaced fluid mix in all proportions or to a local extent resulting in a single phase flow without interfaces. Miscible displacement is an important branch of the EOR methods (tertiary production).

When the two types of fluid displacement are compared, miscible displacement techniques exhibit higher displacement efficiencies and subsequently higher Recovery Factors. This is attributed to the fact that miscible displacement techniques manage to eliminate the capillary forces that keep significant oil quantities trapped in the pores.

Generally, the efficiency of the fluid displacement techniques is described by the following equation:

$$\mathbf{E} = \mathbf{E_S} * \mathbf{E_I} * \mathbf{E_D}$$

Where:

$\mathbf{E_S}$ is the areal sweep efficiency which is the fraction of the reservoir area that is swept by the displacing fluid to the total reservoir area. It is always less than unity and calibrates the fact that there always exist some zones in the reservoir that are not swept by the displacement fluid.

$\mathbf{E_I}$ is the vertical sweep efficiency (or invasion efficiency) which calibrates the fact that some areas of the reservoir are not be invaded by the displacing fluid because of the vertical heterogeneities of the reservoir.

$\mathbf{E_D}$ is the microscopic displacement efficiency which is related with the mobilization of the oil at the pore scale and it is governed by the interfacial (capillary) forces between the displacement fluid and the oil film.

From all the above it is obvious that it is preferred to use a fluid miscible with oil (miscible displacement techniques) because the interfacial forces between the displacement fluid and the oil film are minimized, the term E_D is maximized and so as the overall displacement efficiency (**E**) and subsequently the efficiency of the oil recovery procedure.

Practically speaking, there are two techniques to attain miscibility between the oil accumulations and the injected fluid in order to form the highly effective miscible displacement:

1. **Absolute miscibility** that involves the injection of limited quantity (a slug) of a solvent which is followed by another less expensive fluid in order to drive the solvent along the target reservoir. The injected solvent is 100% miscible with the oil and in the contact a mixing zone of the two fluids is formed. Similarly, the solvent is 100% miscible with the less expensive fluid that follows forming a second mixing zone. The miscible slug injection process must be engineered in such a way so as the quantities of the injected solvent are capable to sweep the entire target oil accumulation. If the quantities of the injected solvent are less than required then the oil accumulations come in contact with the drive fluid that follows and as a result the less effective immiscible displacement is formed. This phenomenon is called miscibility rupture.

2. **Thermodynamic miscibility** that involves the injection of a fluid which under specific thermodynamic conditions (pressure, temperature, phase composition) become miscible with the oil accumulation. It is apparent that in this technique only one mixing zone is formed. Generally, high pressure and low temperature favour the thermodynamic miscibility process whereas the composition of the injected fluid depends on the properties of the targeted oil accumulation.

Miscible flooding methods can be distinguished in the following categories whereas in the **Table 4.1** a general range of the parameters that determine the viability of the miscible flooding EOR methods are presented (NC – Not Crucial): [15] [16] [17]

A. High pressure gas injection   (Thermodynamic miscibility)

B. Enriched gas injection   (Thermodynamic miscibility)

C. LPG / Alcohol slug injection   (Absolute miscibility)

D. CO_2 injection   (Thermodynamic miscibility)

E. N_2 injection   (Thermodynamic miscibility)

Table 4.1: General critiria for miscible flooding EOR methods

EOR method	° API	Depth (ft)	Viscosity (cp)
High pressure gas injection	>40	>5.000	N.C
Enriched gas injection	>26	>2.000	N.C.
LPG/Alcohol slug injection	>30	>1.100	N.C.
CO_2 injection	>22	>2.500	<35
N_2 injection	>35	>6.000	<0.4

4.2 Factors affecting the efficiency of miscible displacements

Viscous fingering

The mobility ratio (M) is the most important factor that finally determines the success of the miscible displacement process. Generally, as mobility (λ) of a fluid in a porous medium can be defined the ratio of the effective permeability of the fluid to the specific porous medium, divided by the fluid's viscosity. The mobility (λ) of oil demonstrates the easiness of oil movement in the reservoir and finally determines the well productivity.

$$\text{Mobility of a fluid: } \lambda = \frac{Keff}{\mu}$$

Subsequently, as mobility ratio (M) is defined the ratio of the mobility of the displacing fluid divided by the mobility of the displaced fluid.

$$\text{Mobility ratio: } M = \frac{\lambda_{displacing}}{\lambda_{displaced}}$$

When the mobility ratio is equal or less than unity meaning that the displacing and the displaced fluid move with the some easiness through the porous medium then the displacing fluid does not penetrate into the displaced oil and the displacement front is stable, as it is presented in **Figure 4.1**.
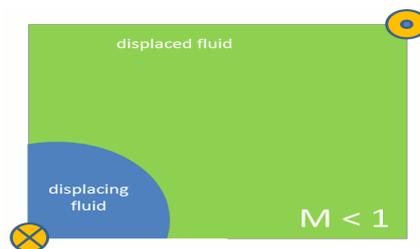
Figure 4.1: Miscible displacement with a stable displacement front

Generally, gases are less viscous than typical crude oils and when are used as displacing fluids, the resulted mobility ratio demonstrates values higher than unity. In this occasion the displacement front becomes unstable and numerous fingers penetrate irregularly in the displaced oil as it is presented in **Figure 4.2**. Eventually, viscous fingering results in early breakthrough of the displacing fluid and finally, in decreased oil recovery.
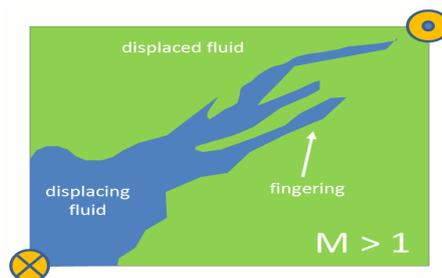
Figure 4.2: Miscible displacement with viscous fingering

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Gravity segregation

Miscible displacement techniques are subjected to the phenomenon of gravity segregation that becomes more intense as the density difference between the displacing and the displaced fluid is increasing. Especially the gaseous phases which are used as displacing fluids tend to flow upwards and override the much denser oil accumulations as it is illustrated in **Figure 4.3**. The induced gravity segregation result in decreased vertical sweep efficiency, in early breakthrough and subsequently in decreased overall recovery factor.
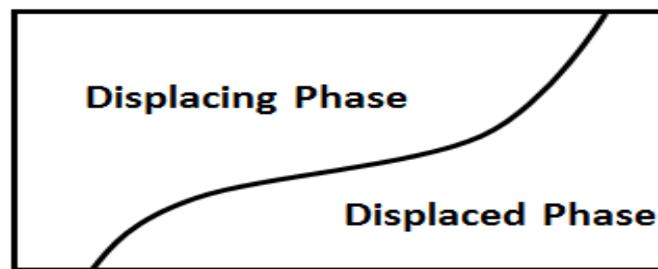
Figure 4.3: Gravity segregation

Channelling

The performance of the miscible displacement techniques is affected drastically by any possible heterogeneities of the reservoir rock among which the vertical permeability stratification seems to be the most significant. The displacing fluid, especially if it is in a gaseous phase, traverses the reservoir rock via the most permeable channel. In the case of a reservoir which demonstrates vertical permeability stratification as it is presented in **Figure 4.4** a large portion of the reservoir's volume may remain unswept and subsequently, the corresponding quantities of oil in the low permeability layers, may remain in their original place. The reservoir stratification has larger effect in fluids with high mobility ratio (M). Besides the unrecovered oil quantities, the reservoir stratification results also in the crossflow between the displacing and the displaced fluids. This phenomenon, depending on the direction of the displacement process may enhance or hinder the oil recovery.
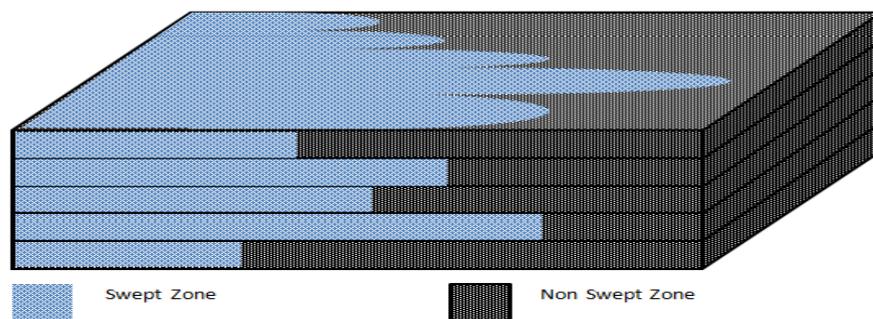
Figure 4.4: Areal and vertical sweep in a stratified formation

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4.3 Miscibility condition

Generally speaking, when the phase behaviour of systems consisting of three components needs to be described the graphical representation of tertiary diagrams are considered to be a good approach as the possible mixtures of the three components can be easily illustrated in a two – dimensional graph. A typical ternary diagram is illustrated in **Figure 4.5**.As we can see, the three different components (A, B and C) of the hypothetical mixture are placed in the three vertexes of the tertiary diagram. Every point in the area of the tertiary diagram represents a corresponding mixture with a specific mole combination of the three components. For example, the point M1 in **Figure 4.5** is a mixture that is consisted by 50% of the component A, 30% of the component B and 20% of the component C. Furthermore, every possible mixture of M1 and M2 mixtures is represented in the tertiary diagram by a point in the line segment M1- M2.
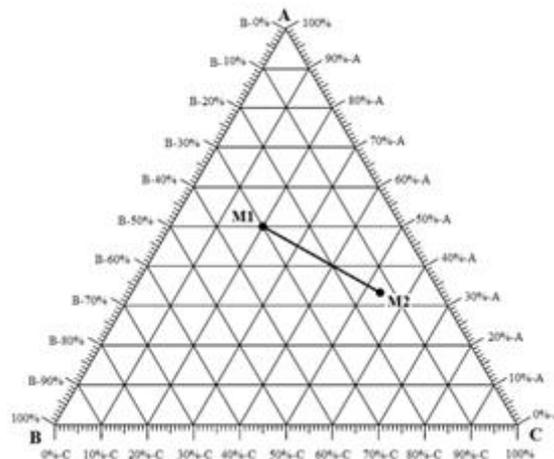
Figure 4.5: Ternary diagram

At every given temperature and pressure, a hypothetical mixture can be a single phase fluid or a diphasic fluid. **Figure 4.6** illustrates the miscibility condition according to which, <u>two mixtures are miscible in all proportions as long as the line segment that connects them do not pass through the two phase region</u>. For example M1 - M2 are miscible in all proportions, as well as M3 - M2 but M1 - M3 are not.
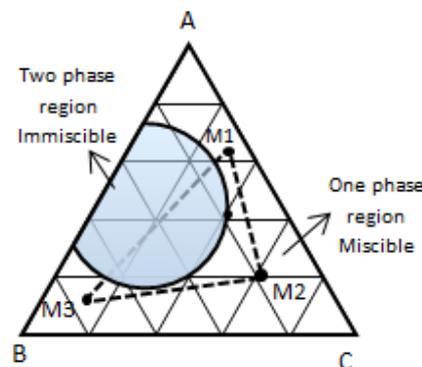
Figure 4.6: Miscibility condition

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The hydrocarbons in the reservoir constitute an extremely complex mixture with numerous components ranging from CH_4 to C_{40+}. In order to describe the thermodynamic behaviour of this complex mixture of hydrocarbons it is recommended to decompose it into smaller groups of hydrocarbons that demonstrate similar thermodynamic properties. These groups are the so called pseudocomponents. In order to describe the thermodynamic miscibility the following three pseudocomponents are formed:

1. **C_1** constitutes the pseudocomponent which contains the lighter - volatile fractions like CH_4, CO_2 and N_2

2. **$C_2 - C_6$** constitutes the pseudocomponent which contains the intermediate fractions and includes all the hydrocarbons from ethane to hexane and sometimes CO_2 and H_2S. This fraction is very important because miscible displacement process relies on the exchange of the intermediate fractions between the displacing and the displaced fluid.

3. **C_{7+}** constitutes the pseudocomponent which contains the heavy fractions of the hydrocarbons mixture means C_7 and heavier.

The above pseudocomponents constitute the three vertexes of the so called pseudoternary diagram that is illustrated in **Figure 4.7.** In the two phase (immiscible) region of the diagram we can see the so called *tie lines*. Each diphasic mixture is represented by a point in these tie lines and the corresponding compositions of the liquid (L) and vapour (V) phases are found in the bubble point curve and in the dew point curve respectively. The critical tie line that comes from the critical point is a tangent to the two phase region and practically defines the **miscible region** where all the mixtures all mutually miscible. Generally, it is known that the diphasic region shrinks when pressure increases at constant temperature. On the other hand when temperature increases at constant pressure, the diphasic region enlarges. From all the above, it becomes clear that during miscible displacement techniques where the miscibility of the displacing and displaced fluid is pursued, high pressure and low temperature conditions favour the mixing process as they reduce the size of the diphasic region.
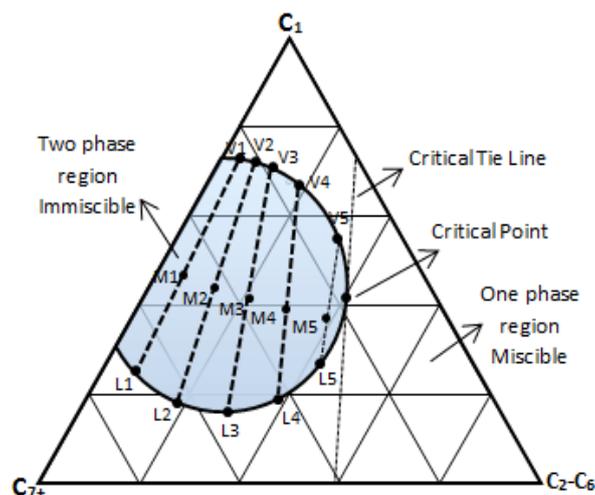
Figure 4.7: Pseudoternary diagram

4.4 High pressure dry gas injection
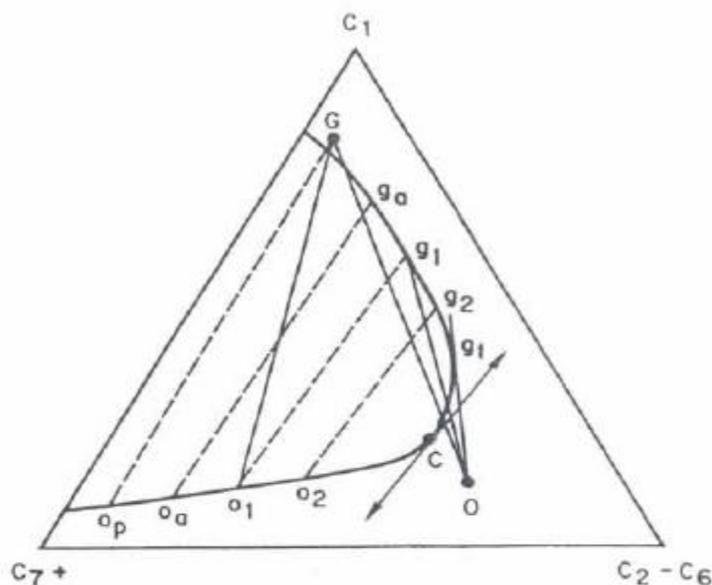
Figure 4.8: Vaporizing gas drive process

General description of the technique

The technique involves the continuous injection of dry gas at high pressure that normally varies between $3.000 - 4.500$ psi. At every circumstances, in order to achieve miscibility in all proportions the injection pressure must be greater than the **minimum miscibility pressure** that is determined by the composition and the thermodynamic properties (P,T) of the crude oil. The increased pressure of the injected gas results in the vaporization of the intermediate components ($C_2 - C_6$) from the crude oil which subsequently get incorporated in the gas flow. The vaporization of the crude oil's intermediate components is the mechanism through which the desirable miscible displacement front between the displacing (natural gas) and the displaced (oil) fluid is achieved. This is why this technique is also named as *vaporizing gas drive*. In order to explain the procedure graphically, using the pseudoternary diagram that is illustrated in **Figure 4.8** the initial composition of oil is represented with O whereas the initial composition of the injected high pressure gas with G. The success of the technique relies on the fact that the displaced oil is rich in intermediate components (light oil with gravity >35° API) this is why point O is placed very close to the C_2-C_6 vertex. In order to achieve sufficient exchange of intermediate components and achieve the desirable miscibility we inject dry gas which is poor in intermediate components. This is why point O is placed very close to the C_1 vertex. More specifically, the procedure of the formation of the miscible displacement front during the vaporising gas drive technique, involves the following steps:

1. **Start of gas injection.** Initially, when the injected gas starts displacing the crude oil, the two fluids do not fulfil the miscibility condition as the line segment O-G passes through the two phase region, as it can be seen from **Figure 4.8.** The result that the oil displacement is not miscible and as a subsequent, quantities of oil of composition O are left behind the gas oil front as it can be seen from **Figure 4.9**. The non miscibility displacement at the first period of gas injection

implies that the area near the injection well will inevitably contain some quantities of residual oil.
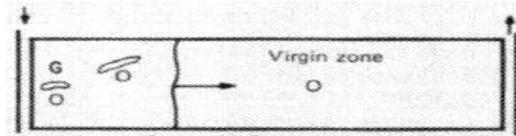
Figure 4.9: Start of injection

2. **Start of phase exchange.** After the initial period of the gas injection, the gas - oil front has propagated towards the production well. As it has already explained quantities of oil of composition O are left behind. Since, the oil and the injected gas are not in thermodynamic equilibrium, phase exchange takes place between the two fluids. The result is that the gas becomes heavier because it incorporates intermediate components and its composition (g_1) becomes more similar to the composition of the reservoir's oil (O) although the displacement still remains immiscible as it shown in **Figure 4.8** and **Figure 4.10.**
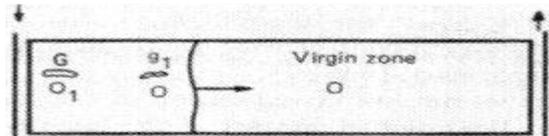
Figure 4.10: Start of phase exchange

3. **Development of phase exchange.** With the development of the procedure the injected gas quantities come in contact with more quantities of residual oil as the distance it has to cover till the gas – oil front has increased as it is shown in **Figure 4.11**. This results in further absorption of intermediate components which make gas heavier (g_2).
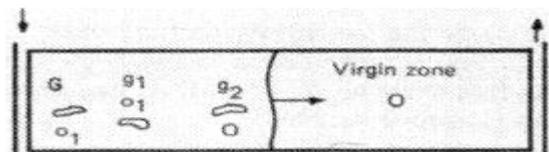
Figure 4.11: Development of phase exchange

4. **Formation of the miscible bank.** The enrichment of the injected gas with intermediate components is continued till a point (g_t) where the miscibility condition with the reservoir oil is achieved. At this point the line segment O – g_t do not pass from diphasic region as it is illustrated in **Figure 4.8** meaning that the miscibility between the two fluids has been achieved. As it can be seen from **Figure 4.12** a miscible bank is formed which results in a piston like miscible displacement where no residual oil is left back. Field experience has shown that a distance of approximately 12 meters from the injection well is required for the formation of the miscible bank.[1]
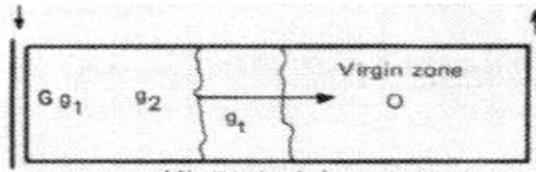
Figure 4.12: Formation of miscible bank

5. **Miscible displacement.** Once miscibility has been achieved and miscible bank has been created, there is no need in injecting natural gas but another less expensive inert gas (for example flue gas) can be used to push the miscible front.

The most important parameter of the procedure is the pressure of the injected gas. From **Figure 4.13** it can be seen that by increasing the pressure of the injected gas, the miscibility is increasing proportionally and so as the oil recovery. When the pressure is increased till the minimum miscibility pressure then miscibility at all proportions is achieved, the miscible bank has been formed and the oil recovery is maximized. From the above it becomes clear that the lower limit of the injection pressure is the minimum miscibility pressure. However, the injection pressure has an upper limit as well as it must be lower than the saturation pressure of the reservoir's oil in order to allow the vaporization of the intermediate fractions.
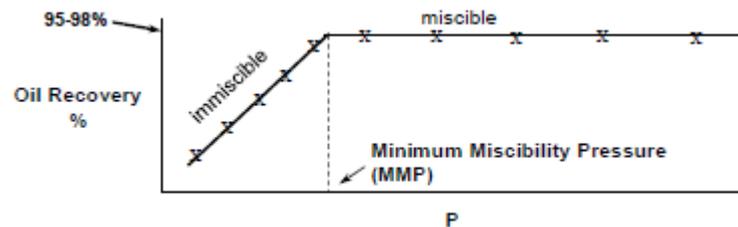
Figure 4.13: Minimum miscibility pressure

Advantages

The main advantage of the method is that the necessary natural gas quantities can be available from the field or adjacent fields. Especially in areas where there is no market to accept the inevitable gas quantities that are produced high pressure gas injection appears as a promising EOR method and a step towards the global effort to reduce the gas flaring.

Disadvantages

As it has already mentioned this technique requires the preservation of the reservoir pressure above the minimum miscibility pressure. To fulfil this requirement enormous quantities of natural gas that have been produced from the same field are reinjected but in the case of gas insufficiency, additional quantities may need to be transferred from other fields increasing by this way even more the high cost of the technique. The technique also requires a capable infrastructure of compressors the operation of which rises furthermore the overall costs.

Field application

As it has already mentioned, for the formation of the miscible bank it is required that the pressure of the injected gas to be above the minimum miscibility pressure. This factor sets a minimum depth of the possible fields where the high pressure gas injection technique can be implemented. The required pressure to sustain the miscibility varies from 3.000 to 4.500 psi depending on the oil properties meaning that the oil reservoir must be at a depth greater than 5.000 ft. Furthermore, the oil must be rich in intermediate components meaning that must be light oil with gravity more than 35° API. Generally, the heavier is the oil the less miscible becomes with the injected gas. Another factor is that dry gas has a commercial value as it can be used as a fuel and when there is an available market, it is not economical viable to use it as an injection agent. The above requirements limit significantly the number of prospective oil reservoirs where high pressure gas injection can be implemented successively as it is more suitable for deep reservoirs, containing light oil and placed in remote areas where there is no market for the producing quantities of natural gas.

The world's largest high pressure miscible gas injection project has been implemented in a cluster of seven oil reservoirs in Harweel area in Oman as it is illustrated in **Figure 4.14.** The **Harweel 2AB EOR project** has been completed in April 2012 with an oil production 23.000bbl/day [2] and it is expected to be in operation for more than 30 years. The successful implementation of the EOR method resulted in the return of the initial investment in just 3 years. The cluster of the seven oil reservoirs is estimated to contain 1.8 billion bbl in place of light sour oil and retrograde condensate. The ultimate oil recovery via primary production is estimated to be around 10% but after the implementation of the miscible gas injection the value is increased to more than 30%. The reservoir's oil is light with gravity ranging between 38 - 50° API and sour as the associated gas contains 5-10% CO_2 and 5% H_2S. The seven oil reservoirs are deeply buried in depths between 3 and 5 km, the prevailing pressures are relatively high varying from 7.000 to 14.000 psi and the permeability relatively low varying from 0.1 to 10 mD. [3] Future plans involve the extension of miscible gas injection to the other Harweel oil reservoirs as well. For this reason, an additional supply of 16 MM sm3/d injection gas from the gas components of Rabad ' s gas fields production is plannes. The Rabad Harweel Integrated Project is estimated to be operational in 2019 raising the Harweel's oil production at 36.000 bbl/day. [4] As it is shown in **Figure 4.14** the success of the high pressure dry gas injection technique can be attributed to a big extent to the productive gas fields that exist in the area and to the available gas pipeline infrastructure.
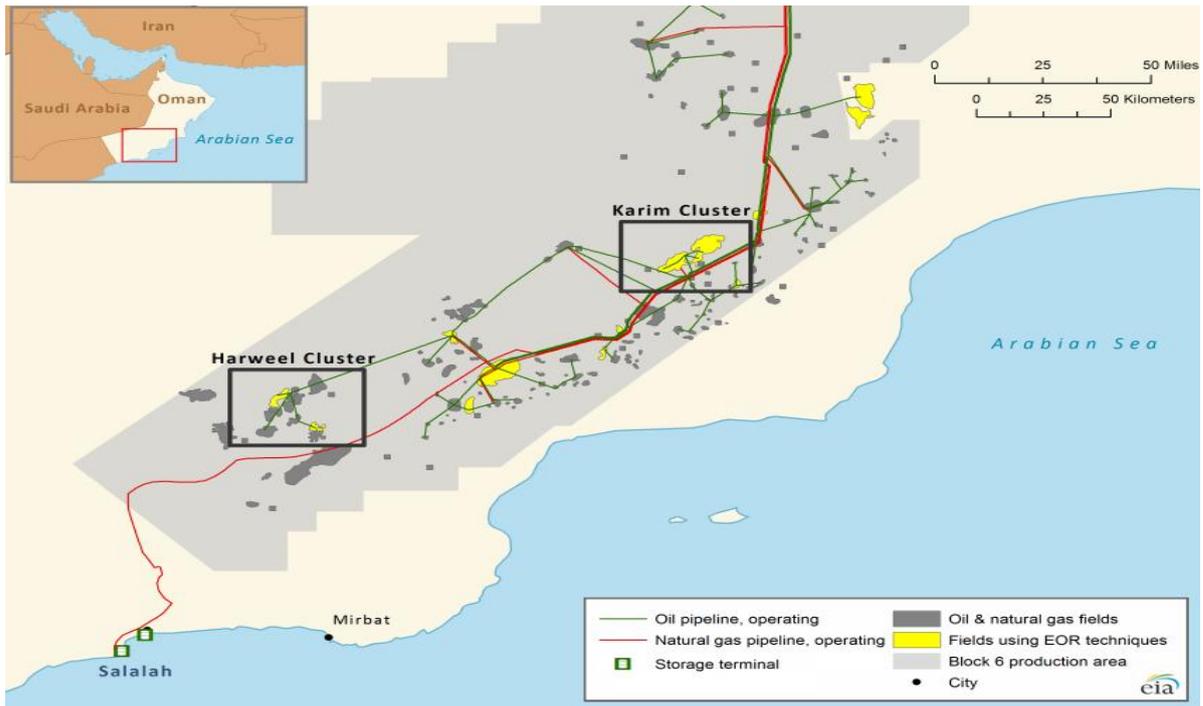
Figure 4.14: High pressure sour gas injection project, Harweel, Oman

4.5 Enriched gas injection
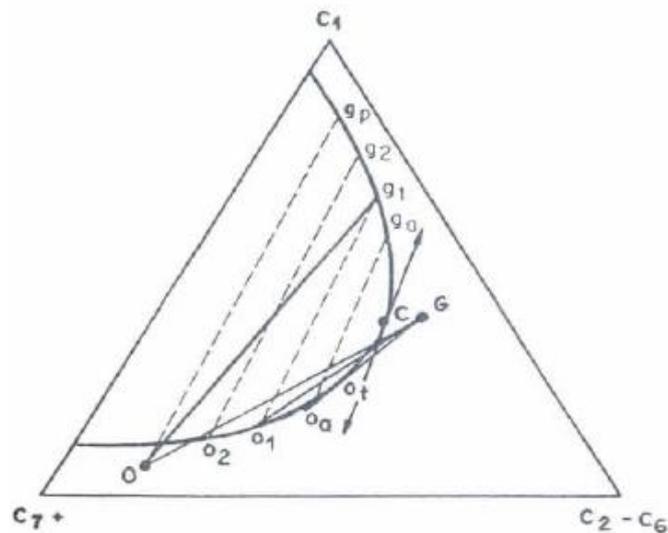
Figure 4.15: Condensing gas drive process

General description of the technique

      The technique involves the continuous injection of enriched at the surface, with intermediate components gas, at a moderate operating pressure that normally varies between 1.500 – 3.000 psi. At every circumstance, in order to achieve miscibility in all proportions the injection pressure must be greater than the **minimum miscibility**

pressure which obviously is lower than the minimum miscibility pressure of the vaporizing gas drive method. Generally, the richer in intermediate components is the injected gas, the lower the injection pressure may be. The necessary quantities of enriched gas can be provided by a gas field near by, or from the separators' first stages unavoidable gas production, or by enriching dry gas quantities with propane or butane. The injected enriched gas is represented with the letter G and the oil in the target reservoir with the letter O in the **Figure 4.15.** It is clear that the composition of the oil O is neat the C_{7+} vertex of the pseudoternary diagram meaning that this technique addresses to medium - heavy oil accumulations. The biggest is the distance between O and G (meaning biggest compositional difference) the greater is the volume of enriched gas that has to be injected. The procedure of the formation of the miscible displacement front during the enriched gas injection technique, involves the following steps:

1. **Start of gas injection.** Initially, when the injected enriched gas starts displacing the crude oil, the two fluids do not fulfil the miscibility condition because the line segment O-G passes through the two phase region, as it can be seen from **Figure 4.15.** The result is that the oil displacement is not miscible and as a subsequent, quantities of oil of composition O are left behind the gas oil front as it can be seen from **Figure 4.16**

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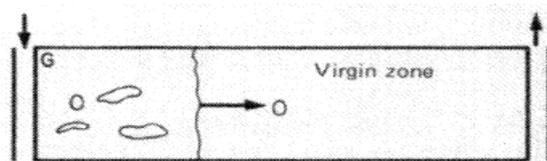
Figure 4.16: Start of injection

</div>

2. **Start and development of phase exchange.** After the initial period of the gas injection, the gas - oil front has propagated towards the production well. As it has already explained quantities of oil of composition O are left behind. Since, the oil and the injected gas are not in thermodynamic equilibrium, phase exchange takes place between the two fluids. The result is that the injected gas becomes drier and its composition changes progressively from G to g_1, g_2 and finally to g_p as it is presented in **Figure 4.15.** From the other hand, the composition of the residual oil changes as well and it becomes lighter from O to o_2, o_1, and finally to o_t because of the absorption of the intermediate components from the passing gas. The concentration of C_{7+} in the oil gradually, decreases. The displacement in this stage remains immiscible as the line segments G - o_2 and G – o_1 pass through the two phase region as it is shown in **Figure 4.15.**

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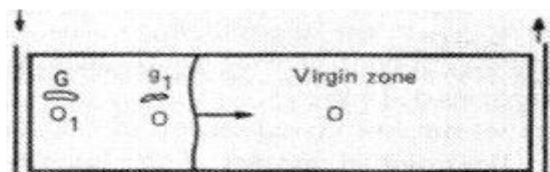
Figure 4.17: Start and development of phase exchange

</div>

3. **Formation of the miscible bank.** The residual's oil composition becomes progressively lighter as it incorporates more intermediate components till a point o_t where the line segment G – o_t do not passes via the two phase region as

is presented in **Figure 4.15**. Then the miscibility condition is fulfilled and miscibility at all proportions is achieved. After this point, the following zones can be distinguished in the displacement procedure as it is presented in **Figure 4.18**:

Zone I: The oil quantities in this area have not been in contact with the injected gas.

Zone II: This area is covered by gas quantities with a composition very poor in intermediate components g_p and which has not been dissolved because the oil progressively became saturated.   These gas quantities will finally be passed by the oil bank (Zone III) and will get incorporated in the driving gas.

Zone III: The oil in this area has been enriched with intermediate components which have been condensed from the drive gas. This is why this method is also called condensing gas drive. A mobile oil bank of composition o_t is formed after which no residual oil is left behind.

Zone IV: The injected enriched gas in this area has not been in contact with any oil quantities yet.
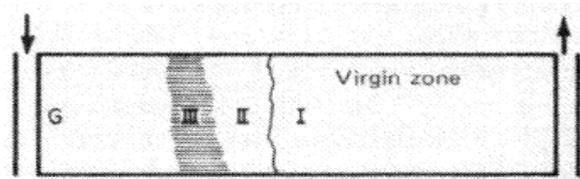
Figure 4.18: Formation of the mobile oil bank

4. **Miscible displacement.** Once miscibility has been achieved and miscible bank has been created, the injection of the valuable enriched gas can be replaced with the more economic dry gas injection just to push the miscible front. Before this replacement it must be ensured that all the quantities of intermediate components that are necessary for the mobilisation of all the target oil accumulation have been supplied via the enriched gas injection.

Advantages

The displacement efficiency of the condensing gas drive is very high as no residual oil is left behind the mobile oil bank, achieving by this way higher recovery factor in the swept zones than the vaporizing gas drive method.

Disadvantages

The main disadvantage of the method is the high value of the injected enriched gas that cannot be recovered totally. In fact, the quantities of the injected enriched and dry gas that are recoverable depend on each reservoir's characteristics. Also, another operational disadvantage is that the miscible bank of the condensing gas drive is not so stable as its formation depends on the intermediate components that the injected gas is

carrying. Any heterogeneity in the intermediate components supply affects negatively the stability of the mobile oil bank.

Field application

As it has already mentioned, for the preservation of the miscible bank it is required that the pressure of the injected gas to be maintained above the minimum miscibility pressure. However, the high concentration of intermediate components lowers the high pressure requirements when compared with the vaporizing gas drive method. More specifically, the richer is the injected gas the lower is the minimum miscibility pressure. But to have an order of magnitude, for the case of condensing gas drive method the prospective reservoir must be buried at a depth greater than 2.000 ft.

A successful enriched gas drive experimental project has taken place in the **Seeligson (Zone 20B-07)** field, in Kleberg County, Texas, U.S.A. It was found out that the attained oil recovery was nearly 100% in the areas of the reservoir that were swept by the enriched gas. From the other hand, high values of mobility ratio and sand heterogeneity resulted in very low breakthrough volumetric sweep efficiency, around 23%. Subsequently, in order to increase the volumetric sweep efficiency simultaneous injection of water and enriched gas was implemented, whereas two years later the injected quantities of enriched gas were replaced by simple dry gas, in order to decrease the cost of the EOR project. After the completion of the project 3.7 million bbl of oil had been produced with an ultimate recovery factor of 50% of the original oil in place when the estimated ultimate recovery factor in the case of the natural dissolved gas drive was only 22.3%.

Concerning the Seeligson field characteristics, it is about sandstone buried at a depth of 6.000ft. The reservoir has an average thickness of 12 ft with the maximum value to be 42 ft in the center of the reservoir. The reservoir demonstrates an av. Permeability 100 mD, an av. porosity 19% and an av. connate water saturation 31%. The reservoir oil was saturated at a reservoir pressure of 3.010 psi and a small gas cap was located on the top of the formation. The produced oil had a specific gravity of 40 °API. [5]

4.6 Miscible slug injection
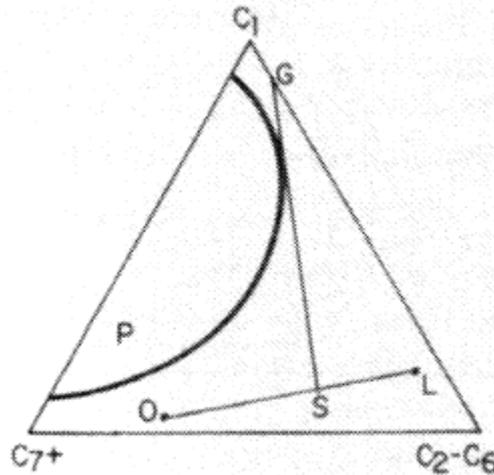
Figure 4.19: Miscible slug flooding process

General description of the technique

The technique involves at first the injection of a solvent to attain absolute miscibility with the oil accumulations where subsequently another drive fluid is injected that is not miscible with the oil but it is miscible with the solvent as it is presented in **Figure 4.20.** Usually as a solvent LPG is used to displace the oil and then dry gas is injected to displace the LPG. Another approach is to inject certain types of alcohols as solvents and then inject water, but this method is not yet commercially available. The condition for the formation of the miscible bank is described for both of the techniques by the pseudoternary diagram that is illustrated in **Figure 4.19.** As we can see, the injected solvent (L) is miscible with the reservoir's oil (O) and with the drive gas (G) as the line segments L-O and L-G do not pass through the two phase region confirming by this way the miscibility condition. The solvent bank as it pushes and displaces the oil, incorporates some oil quantities and its composition change. The composition of the miscible solvent – oil bank is illustrated graphically as a point (S) at the line segment L-O where we can see that it remains miscible at all proportions with the drive gas as long as the line segment S-G do not cross the two phase region. Practically the quantity of solvent that is injected varies between 2 - 9% of the target pore volume. [1]
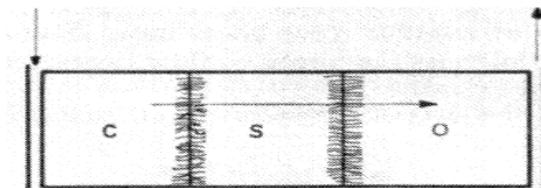
Figure 4.20: Formation of mobile solvent bank

Advantages

The main advantage of the absolute miscibility technique is that it does not require high operational pressure to attain miscible displacement. At pressures higher than 1100 psi LPG becomes miscible at all proportions with the driving gas. Generally, this is the only pressure limit of the technique and subsequently it can be implemented in shallow oil accumulations where the thermodynamic miscibility techniques cannot.

Disadvantages

Generally when hydrocarbons are used in miscible flooding to displace crude oil, due to their low viscosity, the resulted mobility ratios are high and the subsequent volumetric sweep efficiency is very low. In the case where gas is used to displace the LPG slug then the sweep efficiency is further reduced. The volumetric sweep efficiency is improved when water drive is used instead of gas drive. This is the reason why the use of water driven alcohols has been investigated. Furthermore, the stability of the mobile solvent bank is incurred by the fact that LPG tends to evaporate and finally a portion is incorporated by the gas flow. In the case of alcohol based slug, a similar phenomenon occurs, as alcohols tend to absorb water and subsequently the capability of miscibility and the stability of the solvent bank are being reduced significantly. Another disadvantage of the method is the high cost of the required quantities of solvents especially if alcohols are used. The accessibility to these large quantities is also a restraining factor.

Field application

The decreased volumetric sweep efficiency that LPG slug injection demonstrates and the lack of stabilization of the solvent bank make this EOR method suitable to be implemented in a sharply inclined formation like a tall carbonate reef or a flank of a salt dome for example. The high inclination will make gravity forces to stabilize the displacement process and the sweep efficiency will be increased significantly.

A successful implementation of the LPG slug injection has been implemented by Texaco in the Wizard Lake field that is located in Alberta in Canada during 1970s. The reservoir formation is a dolomite with an av. porosity of 9.5%, av. connate water saturation of 7% and with relatively good vertical permeability values. As it is illustrated in **Figure 4.21** the reservoir has a great vertical height and a small areal extent resulting in high inclination which favours the implementation of the LPG slug injection technique. Initially the oil accumulation was 648 ft thick, buried at a depth from 3.386 to 4.034ft. As it is illustrated in **Figure 4.21** the simultaneous injection of gas and LPG from the top and water from the bottom managed to drive the oil to the production wells at the middle of the accumulation height.

The primary production included a combination of gas expansion, water injection and gravity segregation resulted in an ultimate recovery factor near 66% of the original oil in place. After the successful implementation of the LPG slug injection

technique the recovery factor increased at 84%. The technique involved the injection of gas in the gas cap in order to drive the LPG layer and subsequently the oil towards the production wells. It is obvious that gravity enhances the effectiveness of the displacement. The initial pressure of the reservoir was 2.270 psi but after the end of the primary production and before the LPG slug injection was dropped at 1.878 psi forming a gas cap at the top of the formation. Just to have an order of magnitude, during LPG slug injection in the year 1980, 115.534 bbl of LPG solvent, 2.302.771 reservoir barrels of drive gas and 838.169 bbl of water were injected simultaneously. The subsequent annual production was 1.475.528 bbl of oil and 1.037.861 Mcf of gas. [6]
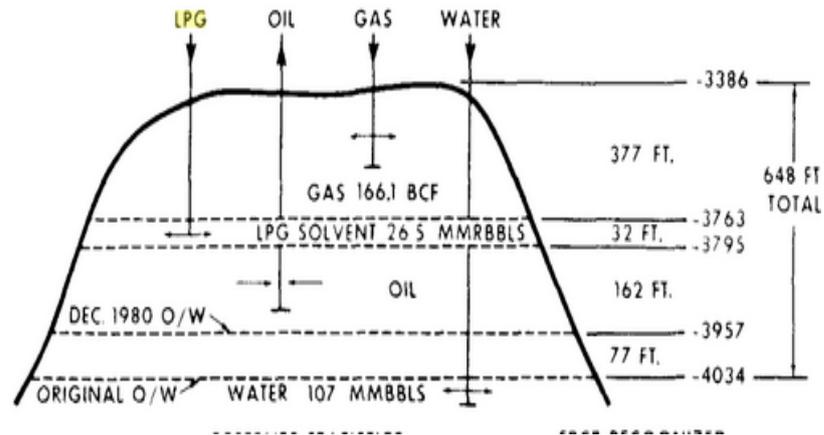
Figure 4.21: Wizard Lake field

4.7 CO_2 flooding
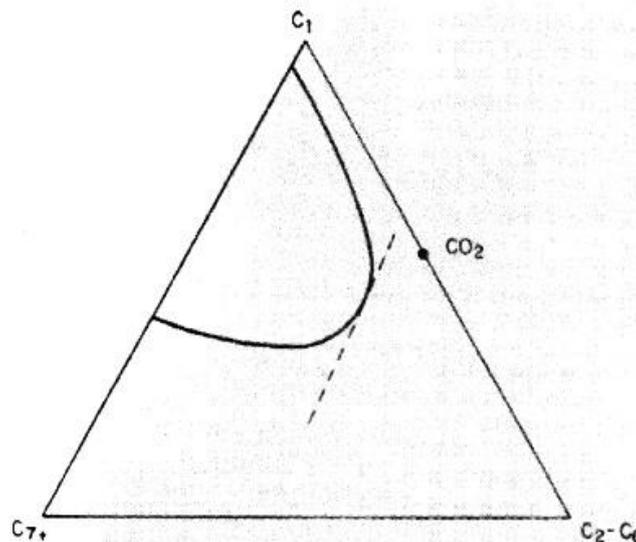
Figure 4.22: Miscible CO_2 injection process

General description of the technique

Carbon dioxide flooding constitutes a commercially viable technique that demonstrates the highest perspectives of all the EOR methods for the tertiary production of light and medium oil accumulations. The unique characteristics that make

CO_2 special to be used as a displacement fluid in EOR methods is first of all its high solubility in oil, secondly its abundance and finally the fact that underground storage of CO_2 quantities demonstrates significant environmental benefits.

The technique of CO_2 injection may result in a partial miscibility or in the desirable, more effective, complete miscibility with the original oil in place. The possible achievement of the thermodynamic miscibility at all proportions depends on the three reservoir oil's properties that are presented below. The combination of these crude oil's properties determines whether the displacement is going to be miscible or immiscible and generally the CO_2 injection technique's feasibility. In **Table 4.2** the criteria for the implementation of CO_2 flooding are illustrated. [7]

1. **Crude oil's composition**. Generally, the value of the minimum miscibility pressure is increasing when oil becomes heavier. Practically, thermodynamic miscibility at all proportions cannot be attained in heavy oil accumulations with oil gravity lower than 22° API.

2. **Crude oil's Pressure.** As it has already explained the size of the diphasic region decreases when the operational pressure increases enhancing by this way the miscibility process. Generally, the minimum miscibility pressure that is required in the case of CO_2 injection is significantly lower than if hydrocarbon gases were injected for the same reservoir conditions and varies between 2.000 – 3.000 psia.

3. **Crude oil's Temperature.** As it has already explained the size of the diphasic region decreases when the operational temperature decreases enhancing by this way the miscibility process.

Table 4.2: Screening criteria for CO_2 flooding

Oil gravity (°API)	Required Depth (ft)
Miscible displacement	
>40	2.500
32-40	2.800
28-31.9	3.300
22-27.9	4.000
Immiscible displacement	
13-22	1.800
<13	Not feasible

Miscible CO₂ displacement

The miscibility condition for the case of CO_2 injection can be represented via the pseudoternary diagram that is illustrated in **Figure 4.22.** The CO_2 based on its molecular weight is represented as a point at the right side of the pseudoternary diagram. The miscibility condition is fulfilled as long as the point that represents the oil composition (O) is in the miscible region that is defined by the critical tie line as it is shown in the pseudoternary diagram. In such a condition, there is miscible displacement of the oil that is based on a **vaporizing – condensing mechanism** that is illustrated in **Figure 4.23.** Mass transfer phenomena occur as the flow of the CO_2 vaporizes the lighter fractions of the oil whereas part of the CO_2 condenses into the oil. The result is that a single phase solution is developed between a gaseous phase that consists of the CO_2 which is enriched with the light hydrocarbon fractions and a liquid phase that consists of the oil which is enriched with the intermediate hydrocarbon fractions. Generally, CO_2 is miscible with short chain hydrocarbons containing fewer than 13 carbon atoms but as the operational pressure increases a greater fraction of intermediate components is extracted from the oil and dissolved in the CO_2. Also, a small portion of residual oil is left behind the mixing front and becomes progressively heavier and less mobile as it loses its light components. Generally, in a miscible CO_2 displacement around 95% of the swept oil quantities can be displaced. [6] Although, the increased theoretical displacement efficiency in the real fields the CO_2 miscible flooding can recover an additional 5% to 15% of the target reservoir's oil in place. A typical scenario is to inject CO_2 in a light oil accumulation, after a waterflood in order to increase the ultimate Recovery Factor from around 45% to 60% and to extend the reservoir life for 15 – 20 years.
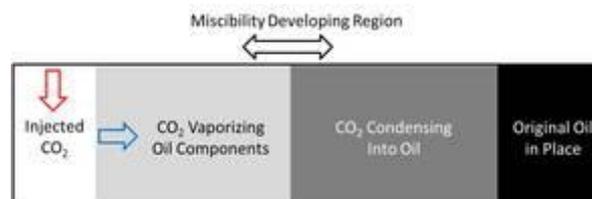
Figure 4.23: CO_2 miscible process

Immiscible CO₂ displacement

When the miscibility condition is not fulfilled meaning the reservoir's oil pressure is too low enlarging the diphasic region or the oil is too heavy then immiscible displacement occurs. It must be noted that immiscible CO_2 displacement may be not as effective as miscible displacement but several field implementations (Lick Creek field in Arkansas or Wilmington field in California) have proved the economical viability of the process. More specifically, during immiscible displacement by CO_2 flooding, the following phenomena occur that increase significantly the oil mobility:

- **Oil phase swelling**: The dissolution of CO_2 in the crude oil makes it to swell and its volume increases from 10 to 20% depending on the oil's properties. [1] By this way, the space that the oil quantities occupy in the pore volume, means

the oil saturation (S_o) increases and disconnected oil blobs may get reconnected forming a continuous pathway of oil.

- **Oil's viscosity reduction**: The dissolution of CO_2 in the crude oil results in a significant reduction of the crude oil's viscosity. In fact, the more viscous is the original oil in place, the sharper is the viscosity reduction. Moreover, the dissolution of CO_2 in the connate water, results in the increase of the water's viscosity. The large decrease in the oil's viscosity combined with the small increase in the water's viscosity result in a significant improvement of the reservoir's fluids mobility.

- **Reduction in the interfacial tensions**: The vaporization of the light and intermediate components into the CO_2 flow result in a significant reduction in the interfacial tensions and subsequently in the residual oil saturation.

Advantages

The lower values of the minimum miscibility pressure, enables the miscible CO_2 injection technique to be implemented successively in reservoirs that are buried at relative shallow depths where the previously mentioned hydrocarbon gases injection techniques cannot. The previous characteristic broadens significantly the spectrum of the oil reservoirs where the CO_2 injection technique could be applied. However this technique cannot be implemented in oil reservoirs that are buried shallower than 2.500 ft without exceeding the fracturing pressure of the reservoir. [7] Additionally, the high solubility of CO_2 in the crude oil makes it capable to extract a heavier fraction of the crude oil's components broadening by this way, the spectrum of the possible oil accumulations where CO_2 flooding could be addressed. Besides the high displacement efficiency that CO_2 demonstrates and described above, it should also mentioned that CO_2 is an abundant, inert gas that cannot be used as a fuel as is happens in the case of hydrocarbon injection methods.

The injection and storing of appreciable quantities of CO_2 in the reservoirs, to enhance the oil production constitutes one of the very limited processes that seem to be capable to reduce the CO_2 emissions and the subsequent greenhouse effect. This specific method demonstrates significant environmental advantages over the other EOR methods which attribute an extra boost to the technique.

Finally, it must be mentioned that CO_2 reacts chemically with the water and carbonic acid is formed (H_2CO_3). The carbonic acid in turn reacts with the carbonate rocks resulting in an increase in the permeability of the formation especially around the wellbore.

Disadvantages

One disadvantage of the method is that the CO_2 injection project must be located near a sufficient and affordable CO_2 source that could be an anthropogenic stationary source (for example a gasification plant) or a finite natural deposit. Otherwise the increased transportation costs of the necessary CO_2 quantities may render the project

not economically viable. Besides, the accessibility it should be mentioned that the cost of a ton of CO_2 is not negligible. Even with via the most advanced techniques, the cost for capturing and compressing a ton of CO_2 from a stationary source cannot be less than 35 € /ton. [8] As a subsequent, the success of the implementation of a CO_2 flooding project can be hindered by the presence of any thief zones in the target formation. Finally, another disadvantage of the method is the corrosive nature of the CO_2 that may damage the down hole and the surface equipment.

Additionally, due to the fact that CO_2 demonstrates low viscosity ratios, the resulting mobility ratio (M) takes high values reinforcing by this way the phenomena of viscous fingering and channelling. Generally, as the oil accumulations become more viscous (heavier), the sweep efficiency decreases dramatically due to the increased viscosity difference between the displacing and the displaced fluid and the mixing front becomes more unstable. This is why CO_2 flooding cannot be implemented effectively in heavy oil accumulations or in stratified / fractured reservoirs. Furthermore, the low density of the CO_2 reinforces gravity segregation phenomena. In order to increase the sweep efficiency in light and medium oil accumulations a technique that involves the alternate water injection is implemented (WAG).

Field application

Generally, the prime factors that make an oil reservoir suitable for a CO_2 flooding project is the oil gravity, the minimum miscibility pressure – meaning the depth of the reservoir and finally the size of the reservoir. As it has already explained the technique of CO_2 flooding is applicable in reservoirs in depths more than 2.500 ft and in oils not heavier than 22° API. Factors of secondary importance can be considered the reservoir's temperature and the oil's viscosity. Furthermore, the increased operational costs which involve among others, the compression and the re-injection of the unavoidable quantities of CO_2 that are produced, practically set an additional limit and make this method applicable in oil reservoirs with oil saturation (S_o) more than 20%. [6] [10]

Nowadays the vast majority of CO_2 – EOR projects are located in the U.S.A. The experience that was gained in the fields of the U.S.A. the last decades has made the CO_2 flooding a reliable, proven EOR technique. Most specifically, currently 125 CO_2 – EOR projects are on operation in U.S.A. producing approximately 284.000 bbl/day (2012 Data) the vast majority of which use miscible oil displacement technique. In the rest of the world CO_2 flooding operational projects are very limited. More specifically, in Brasil there are 2 CO_2 flooding projects, in Trinidad 2 and in Turkey 1. [9]

Practically, when miscible CO_2 flooding is pursued then four injection modes are available as presented below. The selection of the appropriate injection mode is based on the specific reservoir properties.

1. **Continuous CO_2 injection.** This technique involves the continuous injection of pure CO_2. As the quantities of the injected CO_2 increase, the solvent bank size increases proportionally. Simulation studies have shown that the increase of the solvent bank size result in an increase in the ultimate recovery factor but the increment gets smaller and smaller. [11] It must be mentioned that this technique

demonstrates the fastest oil response when compared with all the others and the better injectivity as only one fluid is injected. The drawbacks of this injection mode as it has already mentioned is the poor sweep efficiency and the unstable miscible front due to the intensity of the phenomena of viscous fingering, gravity segregation and channelling.

2. **Water alternate gas injection** (WAG). This method and its variations practically constitute the only applicable technique through which the increased mobility ratios that demonstrate all the gas injection EOR projects can be manupilated. Nowadays, almost all the commercial CO_2 miscible flooding projects have adopted the WAG technique which involves the alternate water and CO_2 flooding. The objective of a WAG process is to increase the sweep efficiency by reducing the phenomena of channelling and viscous fingering as the quantities of water stabilise and control the CO_2 flow. Better results are achieved when the flows of CO_2 and that of water have the similar velocities. The design parameters of the technique are the time cycle and the water to gas ratio or WAG ratio. In most of the fields a WAG ratio of 1:1 is implemented as it is presented in **Figure 4.24** but generally, the optimum WAG ratio is defined by the wetting state of the reservoir rock.
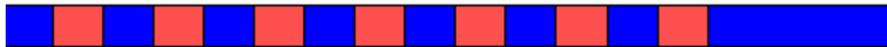
Figure 4.24: Injection schedule with stable WAG ratio 1:1

It must also be mentioned that in most of the projects in order to prevail early breakthrough of the injected CO_2 and for cost reducing reasons the WAG ratio is gradually increased, a technique which is called Tapering and it is presented in **Figure 4.25.**
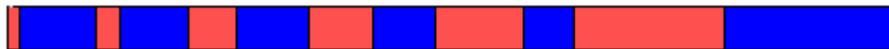
Figure 4.25: Tapered injection schedule

Although, simulation studies of the method establish very high values of displacement efficiency, in the real fields, the phenomenon of gravity segregation between the injected CO_2 and water prevail as distance from the injection well increases. The disadvantages of the interrupted oil production and the slower oil response must also be mentioned. Practically speaking the WAG technique can result in an additional increase in the ultimate recovery factor between 5 and 10%.

3. **Simultaneous water and gas injection** (SWAG). This technique involves the simultaneous injection of water and CO_2. The mixing of the two fluids to form the carbonated water can take place on the surface facilities or downhole. The injection of carbonated water results in lower mobility ratios and subsequently a better sweep efficiency when compared with the previous methods. The nature of the injected fluid makes the process to be advantageous in formations with small heterogeneities, with low permeabilities or naturally fractured reservoirs where the gas injection methods cannot displace the entrapped oil quantities. A drawback of the method is that the quantities of the injected CO_2 are dissolved in the water meaning that for the saturation of a specific oil accumulation,

significant quantities of carbonated water must be injected to provide the necessary CO_2.

4. **Hybrid WAG injection.** The objective of this technique is to combine the advantages of the continuous CO_2 injection that include early production response, and better injectivity with the advantages of the WAG process which demonstrates a more efficient exploitation of the available CO_2 quantities and increased sweep efficiency meaning increased recovery factor. More specifically, the process involves the initial continuous injection of CO_2 quantities that account for 20 to 40% of the HCPV. [11]Then the displacement fluids are injected via the WAG technique.

As an example of successful implementation of the miscible CO_2 flooding technique can be given the **SACROC project** that is located in the Kelly – Snyder field in Texas, U.S.A. which constitutes the world's largest CO_2 - EOR project. Tertiary recovery by CO_2 injection after waterflooding has been implemented in two areas of the field: the four pattern area (4PA) and the seventeen pattern area (17PA). In both cases the WAG mode has been chosen.

In the 4PA area of the field, the CO_2 flooding (WAG) process started at 1981 and ended at1986. During this 5 year period approximately 30% of the reservoir's HCPV was injected as CO_2 and the WAG ratio was ranging from 2 to 8. The incremental oil recovery that resulted from the CO_2 injection is estimated to be 9% increasing the ultimate recovery factor from 57% to the final 66% of the original oil in place. Totally 1.7 MMSTB (0.3 million m^3) of incremental oil were produced. Concerning the cumulative CO_2 demand for every barrel of oil produced 9.5Mscf of CO_2 were necessary to be injected (1.692 m^3 of CO_2 for every m^3 of incremental oil produced at st. conditions).

Similarly, in the 17PA area of the field, the CO_2 flooding (WAG) process resulted in 5% incremental oil recovery after injecting 17% of the reservoir's HCPV as CO_2. The cumulative CO_2 demand was formed at 9.7Mscf of CO_2 for every barrel of incremental oil produced (1.728 m^3 of CO_2 for every m^3 of incremental oil produced at st. conditions). [12]

4.8 N$_2$ flooding
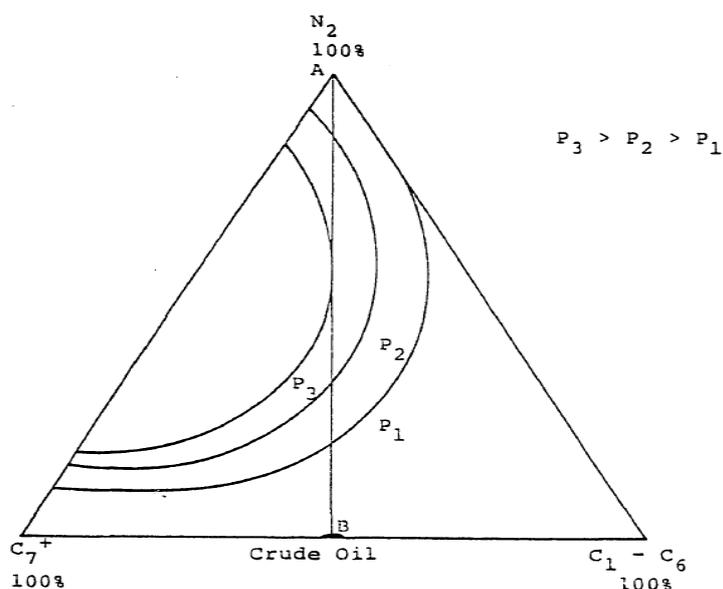
Figure 4.26: Miscible N$_2$ injection process

General description of the technique

The technique involves the continuous injection of Nitrogen at high pressure. The pseudo-ternary diagram that is illustrated in **Figure 4.26** describes the phase relations between the three components system. The first component is pure nitrogen that is placed in the upper vertex of the pseudo-ternary diagram. The second component is the light and intermediate fractions of the crude oil (C$_1$-C$_6$) that is placed in the right vertex. Finally, the third component constitutes the heavy fractions of the crude oil (C$_{7+}$) that is placed in the left vertex. It is obvious that the composition of the crude oil is placed somewhere in the line segment between C$_{7+}$ and C$_1$-C$_6$ in the base of the triangle – point B in **Figure 4.26**. The miscibility condition is fulfilled as long as the line segment N$_2$ – B does not pass from the two phase region. From the pseudo-ternary diagram above it can be conducted that N$_2$ miscible flooding can be implemented only in high pressures and for light oil accumulations.

The miscible displacement of the crude oil is based on a **vaporizing mechanism** that results in a continuous compositional change of the displacing and the displaced fluid. As the flow of nitrogen come in contact with the crude oil, a continuous process of mass transfer occurs as the light and some intermediate components evaporate and get incorporated in the gaseous phase. Concerning the crude oil quantities which are left behind become progressively heavier. During displacement process the following distinct zones are formed:

1. **Transition zone.** Initially, the injected nitrogen is pure but as it gets in contact with the crude oil some of the light and intermediate components are vaporised and partially enrich the flow of Nitrogen. When the partially enriched Nitrogen propagates in the reservoir and comes in contact with new quantities of crude oil then a heavier fraction of intermediates is vaporized, enriching the Nitrogen

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flow further more. After several multiple contacts, the flow becomes so enriched (critical composition) that is miscible with the crude oil and then the desirable miscible front is formed. At critical composition the enriched gas is consisted primarily by Nitrogen for example 80%.[13] After the miscible front, the composition of the flow gradually changes and gets more enriched with intermediate components till the formation of a slug of enriched gas where the composition of the flow gets stabilised. Generally, with increasing operational pressure, the transition zone becomes shorter.

2. **Slug of enriched gas**. This area where the composition of the flow remains stable and much enriched with intermediate components is located at the displacement front and is a part of the miscible zone. Laboratory experiments have shown that this slug of enriched gas is consisted of very low quantities of Nitrogen for example 8.6% (for injection pressure 4.000 psia and crude oil of 43°API) whereas the rest of the molar composition is light and intermediate hydrocarbons. [13] In the slug of enriched gas, the high concentration of the intermediate components raises significantly the viscosity of the displacing fluid. This result in a decreased viscosity difference between the displacing and the displaced fluid meaning a lower mobility ratio (M) and subsequently results in improved displacement efficiency.

Advantages

The most important advantage of the technique is that Nitrogen constitutes the cheapest and the most abundant injection gas when compared with all the previously mentioned. Liquid Nitrogen is produced at relatively low cost, from the fractional distillation of the liquefied air via the cryogenic process that involves compression and progressive refrigeration of the atmospheric air. It is obvious that facilities to produce liquid nitrogen can be settled everywhere. Additionally N_2 is a completely inert gas and as a result corrosion problems in the surface and downhole equipment are totally prevented.

Disadvantages

The most important disadvantage of the N_2 flooding is that as a technique demonstrates a very narrow spectrum of the possible oil accumulations where it could be implemented. This is because as a technique has the highest value of minimum miscibility pressure (MMP) of all the other techniques which require the reservoir to be deeply buried. Moreover, as it has already explained the technique addresses to light oils. These two restrictions possibly explain the very few implementations of the technique in the real fields.

Field application

The technique of N_2 flooding is applicable in reservoirs which are buried at least 6.000ft deep in order to inject in high pressure the Nitrogen without fracturing the reservoir. Just to have an order of magnitude, the depth range of the reservoirs where N_2 flooding projects were applied, is between 10.000 and 18.5000 ft. [17] In order to enhance the miscibility, as it has already explained from the pseudo-ternary diagram, the crude oil must be rich in light and intermediate components. Practically, N_2 addresses to crude oils lighter than 35°API. Furthermore the technique has been proved that is more effective in under saturated oil accumulations with low content in methane (C_1). In the real fields the WAG technique has also been implemented with N_2 flooding to increase the sweep efficiency and subsequently the ultimate recovery factor.

A successful implementation of the miscible N_2 flooding technique has taken place in the Jay field that is located in Alabama, U.S.A. The reservoir is deeply buried at 15.000ft around 350 ft thick and contains very light oil 50°API. The reservoir pressure is around 7850 psia making the oil undersaturated by approximately 5.000 psi. The av. porosity of the reservoir is 14% whereas the av. permeability 20 mD. One reason for the success of the N_2 flooding is that the reservoir combines the relatively good horizontal permeability with the very poor vertical permeability which prevents gravity segregation phenomena.

The primary oil production started at 1974 whereas at the same time water flooding was implemented to prevent the fast pressure decline. The N_2 flooding began in Dec 1981 and the WAG injection mode was implemented with a WAG ratio equal to 4. As it can be seen from **Figure 4.27** the incremental oil recovery that results from the N_2 injection is forecasted to be 10% increasing the ultimate recovery factor from 50% to the final 60% of the original oil in place. It is obvious that the field life extended for more than 10 years by implementing N_2 flooding. [14] Successful N_2 flooding projects have also taken place in the East Bingerfield in Oklahoma, U.S.A. and in Lake Barre field in Louisiana, U.S.A.
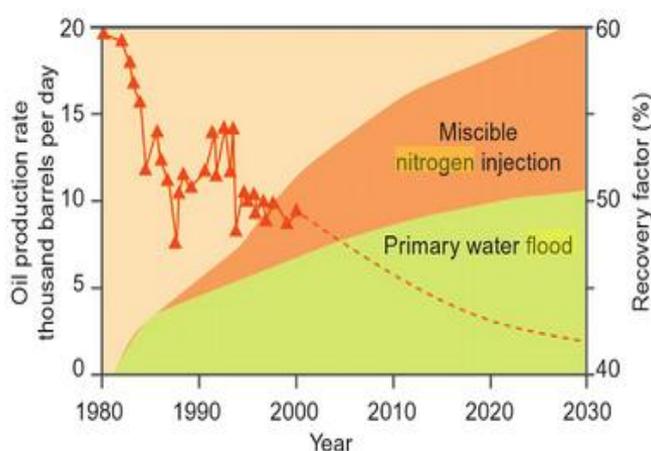
Figure 4.27: Oil recovery from Jay's miscible nitrogen flood

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Chapter 5 EOR – Chemical Flooding

5.1 Introduction

Chemical EOR methods are implemented in depleted – mature reservoirs that have been already water flooded. It is a fact that for most reservoirs, primary production followed by water flooding can result in a recovery factor of around 35% of the oil originally in place. Most of the oil quantities are left back in the reservoir either because they have been by passed from the water flow or because they are restrained by capillary forces. By injecting specific chemical solutions as displacing fluids it is aimed to reduce the previously mentioned phenomena by decreasing the mobility ratio between the displacing and the displaced fluid or by reducing the interfacial tensions between oil and water quantities.

Chemical flooding methods that have been proved to be commercially viable can be distinguished in the following three categories. The mechanism that each chemical flooding method uses to displace the residual oil quantities is also mentioned. Practically, a combination of these methods is used. In the **Table 5.1** a general range of the parameters that determine the viability of the chemical EOR methods are presented (NC – Not Crucial). In this chapter only the chemical combinations which have proven to be commercially viable will be analysed. Generally, most of the chemical EOR projects nowadays make use of polymer flooding or ASP flooding. [2] [4] [5]

A. Polymer flooding   (Mobility Ratio reduction)

B. Alkaline flooding   (Interfacial Tension reduction)

C. Surfactant flooding   (Interfacial Tension reduction)

Table 5.1: General criteria for chemical flooding EOR methods

EOR method	Salinity (g/L) TDS	Viscosity (cp)	Permeability (mD)	Temperature (°C)
Polymer flooding	<200	<10.000	>10	<140
Alkaline - Polymer flooding	<200	<10.000	>50	<93
Surfactant - Polymer flooding	<200	<5.000	>10	<93
ASP flooding	<200	<5.000	>10	<100

In order to make clear how each category of chemicals affects and improves the oil production it is necessary to mention the definition of the overall oil recovery efficiency:

$$E = E_V * E_D$$

Where:

E_V is the volumetric sweep efficiency or macroscopic displacement efficiency. It can be defined as the fraction of the pore volume that has been swept by the displacing fluid divided by the total volume of the flooded area. It can be defined also as the product of the areal sweep efficiency (E_S) with the vertical sweep efficiency (E_I). $E_V = E_I * E_D$

E_D is the microscopic displacement efficiency which is related with the mobilization of the oil at the pore scale and it is governed by the interfacial (capillary) forces between the displacement fluid and the oil film. It can be defined as $E_D = (S_{oi} - S_{or}) / S_{oi}$ where S_{oi} is the initial oil saturation and S_{or} is the residual oil saturation.

Polymers as it has already been mentioned, aim to the reduction of the Mobility Ratio. This is achieved by increasing the viscosity of the displacing fluid which results in the decrease of its relative permeability. Volumetric sweep efficiency is a function of the Mobility Ratio among other parameters. In fact, by using polymers the first term of the overall oil recovery is improved means the volumetric sweep efficiency (E_V).

Alkalis and Surfactants as it has already been mentioned, aim to the reduction of the Interfacial Tension. This is achieved by the formation of soaps or microemulsions in the reservoir which decrease significantly the Interfacial Tension between the displacing and the displaced fluid. The lowering of the Interfacial Tensions results in the decrease of the residual oil saturation S_{or}. Subsequently, by using Alkalis or Surfactants the second term of the overall oil recovery is improved means the microscopic displacement efficiency (E_D).

From all the above it can be deducted that the maximization of the overall oil recovery efficiency can be achieved via a combination of the previously mentioned chemicals so as to improve both the first term (E_V) and second term (E_D).

5.2 Polymer flooding
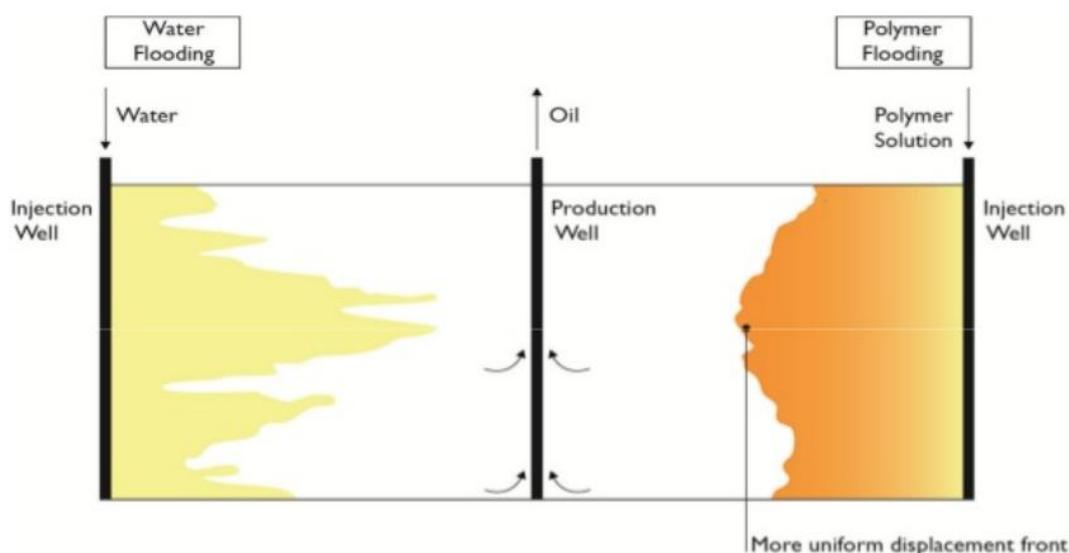
General description of the technique

Polymer flooding constitutes the most applied technique among all the other chemical EOR methods. This is attributed to the fact that polymer flooding is reliable technique that has the possibility to be implemented in a wide range of oil reservoirs. Polymer flooding aims to control the mobility ratio (M) and to increase by this way the sweep efficiency of the displacement process. This is carried out by injecting a mobility control agent – a solution of polymers in order to increase the viscosity of the displacing fluid. The subsequent decrease in the mobility ratio between the displacing and the displaced fluid has as a result the formation of a more uniform displacement front as it is illustrated in **Figure 5.1** which finally results in an increase in the ultimate recovery factor. The process involves the injection of a slug – solution of polymers that normally account for 30 - 50% of the target reservoir's pore volume which is then followed by water / brine injection to drive the oil bank to the surface. Field implementations have shown that polymer flooding has the potential of an incremental recovery factor that could range between 5 – 30% of the oil originally in place. [3]

Another, secondary mechanism through which polymer solution displaces oil is attributed to polymers' viscoelastic properties. Generally, the shear stresses that are developed in the interfaces between oil and polymer solutions are higher when compared with the shear stresses in the case of water displacement. As a result a higher pull force can be applied when polymer solution is used as a displacing fluid and subsequently more quantities of oil can be displaced.

In polymer flooding projects, water soluble polymers are used which can be classified in the two categories presented below. The selection of the appropriate type of polymer is based on each reservoir's characteristics. The reservoir permeability and the oil viscosity define the molecular weight of the polymer whereas the absorption level defines the required degree of hydrolysis.

1. **Synthetic polymers** are those which are mostly used in polymer flooding projects as they demonstrate greater viscoelasticity and they are generally available at lower prices when compared with the biopolymers. In most cases partially hydrolyzed polyacrylamides (HPAM) are used. The performance that synthetic polymers exhibit is strongly hindered by the presence of brine water and it depends strongly on their molecular weight and their degree of hydrolysis.

2. **Biopolymers**: This group of polymers (is also called polysaccharides) is synthesised by microbial activity and the most used representative is the xanthan gum. Their performance in not influenced by the presence of brine water and are quite resistant to mechanical degradation but they are more sensitive in thermal and microbial degradation when compared with the synthetic polymers. Most of the times biocides are injected simultaneously to prevent microbial degradation whereas as a temperature limit for most of the biopolymers can be considered the value of 70 °C. [3]

Advantages

The increased sweep efficiency that polymer flooding demonstrates, results in reduced water quantities that need to be injected when compared with the conventional water flooding. The acquisition and management of less water quantities may have significant positive economic impacts especially in the case of offshore or desert area oil production.

Disadvantages

Perhaps the most important disadvantage of the polymer flooding process is the difficulty in the water treatment that the method encompasses. Surface water management facilities have to deal with the viscous and anionic charged character of the produced polymer water which in addition contains oil and solid particles. The difficulty in meeting the requirements for disposal or re-injection of the produced polymer water often obstructs the implementation of polymer flooding, besides its possible effectiveness.

Another disadvantage of the method is the loss of injectivity (injection rate per pressure drop of injection fluid) as a natural consequence of the increased viscosity of the injected polymer solutions. This phenomenon is more intense in low permeability formations. To overcome the loss of injectivity it is required either to increase the operational pressure of the injection wells or to fracture the formation around the well. It must be also referred that when injecting synthetic polymers (HPAM) there will be some reduction in the reservoir's permeability due to adsorption phenomena.

Finally, the technique is not compatible with all types of reservoirs since (thermal, chemical or bacterial) degradation of the polymers should be avoided.

Field application

Technically, the admixture of polymers in the injected water will definitely increase the sweep efficiency and subsequently the ultimate recovery factor at any possible reservoir. The economic viability of a polymer flooding project relies on the induced benefits meaning the reduction in the mobility ratio and subsequently the increase in the ultimate recovery factor when compared with the cost for the corresponding polymer concentration. Generally, polymer flooding becomes profitable in two types of oil reservoirs:

- Reservoirs with high degree of heterogeneity where conventional water flooding bypasses significant oil quantities. Polymer flooding decreases the fluids' mobility in the high permeability layers resulting in a more uniform displacement front.

- Reservoirs that contain medium oils which result in unfavorably high mobility ratios. Polymer flooding decreases the mobility ratio between displacing and displaced fluid and improves the sweep efficiency.

In both the cases mentioned, means reservoirs with heterogeneities or reservoirs where high mobility ratios occur the result is early breakthrough of the water which is followed by a production with increasing water cuts. Polymer flooding seems to be a possible solution to reverse the situation and to accelerate oil production.

Moreover, the reservoir must exhibit high values of mobile oil saturation which means that the target oil accumulations must have low viscosity (light or medium oils) and the formation must have good permeability. Most of the implementations have taken place in sandstone reservoirs. One main reason for this is the fact that carbonate rocks are positively charged increasing by this way the undesirable retention via absorption of the negatively charged synthetic polymers. In carbonate rocks cationic (positively charged) synthetic polymers can be used, but generally anionic synthetic polymers have been proved to be more efficient and economic. Clays as well, cause significant absorption of the synthetic polymers and must be avoided. Aquifers cause dilution and losses of the injected polymers and must be avoided too.

Any polymer flooding project must observe the following two fundamental constraints:

- Temperature constraint: Reservoir's temperature must be low enough to avoid thermal degradation of the polymers. For most of the polymers used, this temperature limit is set at 140 °C. [5]

- Salinity constraint: Reservoir's connate water salinity must be lower than 200 gr/L TDS (Total Dissolved Solids). Higher concentrations decrease significantly the solution's viscosity. [5]

In 2015 more than 50 operational polymer injection projects were recorded. [5] One of the successive implementations of the technique has taken place in south Oman in the Marmul oil field. Marmul oil field is a good permeability sandstone reservoir that exhibits a high degree of heterogeneity and contains medium – heavy oil (22 °API) with an average viscosity around 90 cP. In order to decrease the mobility ratio and to mobilize the unswept oil quantities that are left behind after secondary production (water flooding) a full field polymer flooding project started to operate at 2010 (April). The specific implementation constitutes one of the very few operational full field polymer flooding projects in the world.

The polymer that was used was synthetic type with viscosity 15 cp at the wellhead and it was injected via 27 wells at a total flow rate 13.000 m^3/day. The injectivity problems that the technique of polymer flooding includes were overcame by small scale fracturing in most of the injection wells and by processing the injecting water so as to be free of oil droplets and solids. For the purpose of the last requirement a two stage treatment system was installed.

The results of the polymer flooding have been encouraging and are illustrated in **Figure 5.2.** As we can see after the start of the polymer flooding, the gross liquid production is gradually decreasing (light blue line). This is a result of the reduced required injected quantities when polymers are used. The water cut (dotted lines) is also decreasing from around 95% to 90% for the same reason. As far as the oil production is concerned (red line) we can see that it has a good response to the polymer flooding and soon follows an upward trend. Polymer flooding is planned to last for 26 years in total and it is expected to result in an incremental Recovery Factor of 10%. [6]
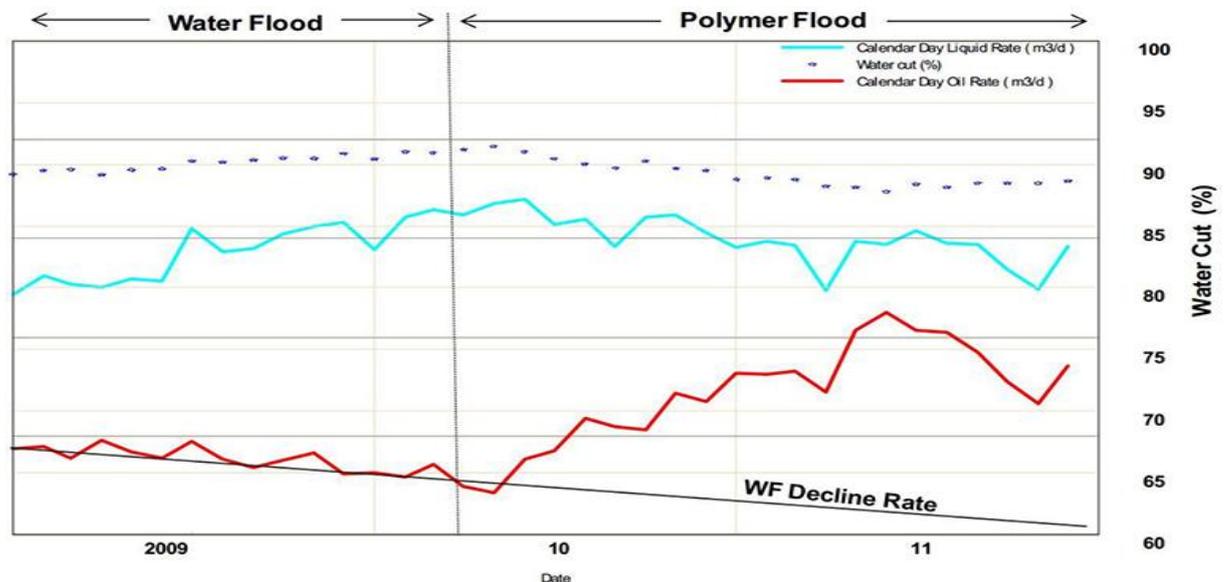
Figure 5.2: Production in Marmul oil field before and after polymer flooding

5.3 Factors affecting the efficiency of Polymer flooding

The flow of the high molecular polymer solutions in a reservoir's matrix can be characterized as very complex and is determined by the Non-Newtonian character of the polymers and the phenomena of retention and degradation. These three factors make impossible to calculate the exact viscosity of a polymer solution as it flows in a reservoir.

Polymers: Non-Newtonian fluids

In Newtonian fluids the apparent viscosity depends only on Temperature and to a lesser extent on Pressure and it constitutes a characteristic of the fluid. As it can be seen from **Figure 5.3** viscosity does not depend on the shear rate as far as Newtonian fluids is concerned. From the other hand, in Non − Newtonian fluids the apparent viscosity depends not only on Temperature and Pressure but on the Shear Rate as well. More specifically, polymer solutions exhibit pseudoplastic behaviour which means that the apparent viscosity decreases when the applied shear rate is increasing – blue line in **Figure 5.7.**
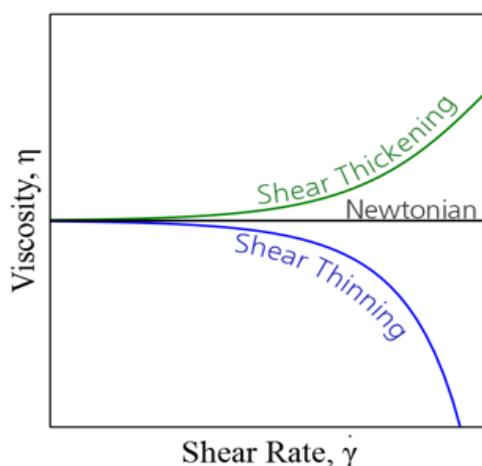
Figure 5.3: Viscosity of Newtonian and Non - Newtonian fluids as a function of shear rate

Polymer Retention

The retention of the polymer solution on the porous medium is occurring via the mechanisms of **adsorption**, **mechanical entrapment** and **hydrodynamic retention**. In the overall polymer retention the mechanism of adsorption contributes the most whereas hydrodynamic retention in some cases can be negligible. The three mechanisms of polymer retention are presented in **Figure 5.6**. Polymer retention has two significant impacts. Firstly, the polymer slug is decreasing as the flow propagates in the reservoir with subsequent loss of costly polymer solution. Secondly, the permeability of the formation is reduced irreversibly. The extent of the polymer retention depends on the combined properties of the reservoir rock and the corresponding polymer solution that is used.

1. Adsorption

When synthetic polymers flow in the porous medium they are strongly adsorbed on mineral surfaces. The adsorbed synthetic polymers increase the restriction in the flow and subsequently decrease the apparent permeability of the formation. For this reason the mobility of synthetic polymers in a porous medium is decreased when compared with the mobility of water or with the mobility of biopolymers. This reduction in mobility is described by the resistance factor (**R**) and it is always R > 1. Moreover, after the displacement of the polymer solution by the water drive, the reduction in the formation's permeability remains. The undesirable phenomenon of adsorption is controlled by partial hydrolysis of the synthetic polymers.

$$\text{Resistance factor: } \mathbf{R} = \frac{M_W}{M_P}$$

Where:

Mw is the mobility of water

MP is the mobility of water containing polymer

The undesirable phenomenon of polymer adsorption in the surfaces of the porous medium is controlled at an extent, by partial hydrolysis of the synthetic polymers. During hydrolysis a percentage of the amide groups ($CONH_2$) of the synthetic polymers is converted into carboxyl groups (COO^-). Practically, in the polymer solutions that are used, the percentage of amide groups that are converted to carboxyl groups by hydrolysis, ranges between 15% and 35% (degree of hydrolysis).[4] In **Figure 5.4** the hydrolysis of the amide group when it reacts with sodium hydroxide is illustrated. Heat is provided to enhance the reactions.
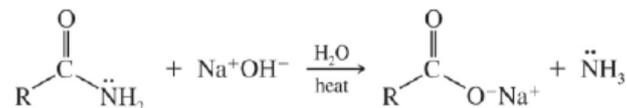
Figure 5.4: Hydrolysis of amide group via sodium hydroxide

A side effect of hydrolysis process is that polymers get negatively charged because of the carboxyl groups that are formed. In this case, polymer chains are covered with negative charges and they tend to stretch as a result of the repulsive forces. When the polymer solution comes in contact with salts that are diluted in the connate water as it is presented in **Figure 5.5** then the repulsive forces are weakened, the stretch of the chains is reduced and subsequently the viscosity of the solution is decreased. Generally, the higher the salts concentration in the connate water, the more is the decrease in the solution's viscosity. This is the reason why synthetic polymers are less effective in reservoirs with increased salinity.

Figure 5.5: Salinity discharges the polymer chains which results in their random configuration

2. Mechanical entrapment

This type of polymer retention involves the entrapment of the big molecules of the polymer solution in the small pore throats of the formation. It is obvious that mechanical entrapment contributes more to the overall polymer retention in low permeability reservoirs. It must also be mentioned that the phenomenon of mechanical entrapment actually sets a limit in the molecular weight of the polymers that are going to be used for a specific reservoir's permeability.

3. Hydrodynamic retention

Hydrodynamic retention is the result of the hydrodynamic force that acts upon polymer molecules and prevent them to move forward. Generally, this type of retention is completely reversible and can be neglected in low flow rates.
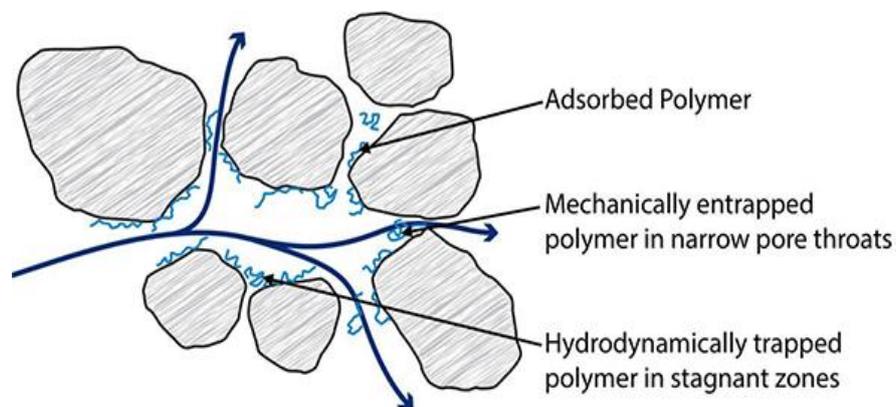
Figure 5.6: Mechanisms of polymer retention

Polymer Degradation

One basic characteristic of the polymer flooding is that the viscosity of the injected polymer solution is gradually decreasing as it propagates in the reservoir. The degradation of the polymers meaning the decomposition of the large molecules to smaller ones, which has as a result the decrease of the polymer solution's viscosity and subsequently, the decrease in the effectiveness of the polymer flooding is occurring via the mechanisms presented below:

1. Thermal degradation.

The thermal sensitivity of the polymers set the reservoir's temperature as a constraint that finally determines the allowable depth of polymer flooding. For most of the polymers used, thermal degradation starts at around 125 °C and is total at 175° C. [1] The vast majority of the polymer flooding implementations have occurred in reservoir temperatures less than 200°F (93°C). [2] Theoretically, temperature resistant polymers could be used like terpolymers or acrylamide copolymers but their increased cost, prevent their implementation in the real fields.

2. Mechanical degradation.

This type of degradation is taking place almost instantaneously at the injection point and is attributed to shear stresses that cut the long molecular chains to smaller ones. Mechanical degradation depends mostly on the reservoir's permeability and the flow rate of the solution. Longer polymer molecules are more sensitive to shear stresses and subsequently to mechanical degradation when compared with shorter ones.

3. Chemical degradation.

The presence of **Oxygen**, that can be contained in the injection water where polymers are dissolved or in the hydrocarbon accumulations activate chemical reactions that cut the polymer chains. In order to remove the Oxygen quantities of the polymer solution stabilizing chemicals are added in the surface facilities. **Iron** concentrations in the rock formation also contribute to the polymers' chemical degradation. More specifically, the high molecular weight chains are more prone to oxidative degradation. Practically, in order to retard this phenomenon, sulphites or formaldehyde can be added to the polymer solution.

4. Biological degradation

Biological degradation is attributed to the activity of the bacteria that might be in the connate water. Bacteria destroy the polymer chains as they introduce them in their metabolism. Generally biopolymers exhibit higher sensitivity to biological degradation than synthetic polymers. Factors like temperature, pressure and type of bacteria affect the extent of the degradation. Ii order to minimise biological degradation the admixture of biocide to the polymer solution is highly recommended.

From the above it can be deducted that long molecular chains are more sensitive to degradation and retention mechanisms. The reservoir properties like for example permeability and temperature determine a spectrum of possible polymers - according to their molecular weights, that can be used effectively. It should be mentioned that when using polymers of lower molecular weight to achieve a specific viscosity increase, a bigger quantity is needed when compared with polymers of higher molecular weight, increasing by this way the cost of the necessary polymer solution to be injected. From the other hand, when using polymers of high molecular weight, for the same injected viscosity a far less viscosity in the reservoir will result when compared with low molecular weight polymers.

5.4 Alkaline flooding
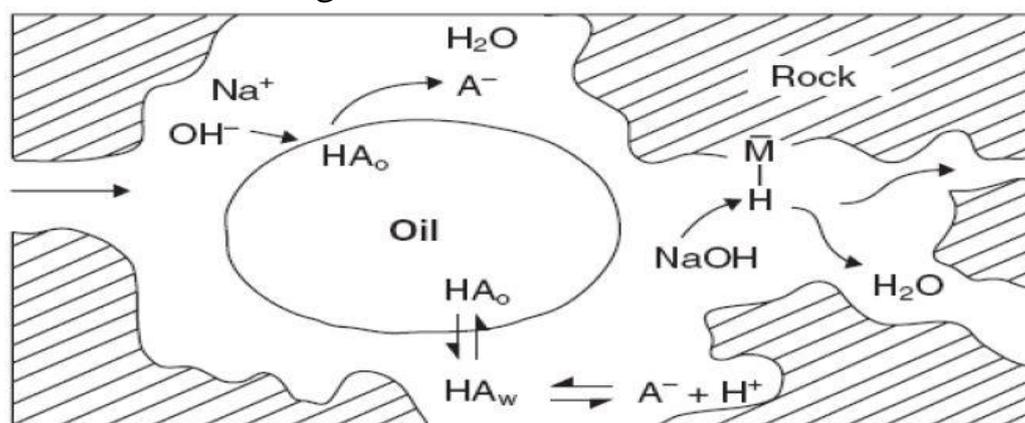
General description of the technique

Alkaline flooding, also known as caustic flooding, demonstrates the lowest cost of implementation of all the other chemical EOR methods nevertheless, as a technique has never been applied successfully independently but always in combination with polymer or surfactant flooding.

The technique manages to increase the ultimate recovery factor by injection of an alkali slug at a pH value that ranges between 10 and 12. Generally, alkalis are water soluble substances and when they are dissolved in water they release hydroxide ions (OH^-). For the preparation of the alkali slug, three types of alkalies are used mostly **NaOH** (Sodium hydroxide), **Na$_4$O$_4$Si** (Sodium orthosilicate) and **Na$_2$CO$_3$** (Sodium carbonate). Sodium hydroxide is the most used whereas sodium carbonate the least used. Sodium orthosilicate is mostly recommended when waters with high hardness are encountered. The technique involves four displacement mechanisms that most of the times act simultaneously and are described below. Depending on the displacement mechanism that is reinforced the recovery process could emphasize more to the residual oil of the already swept zones of the reservoir or to the relatively lower permeability, unswept zones.

In the first case alkaline waterflooding aims to reduce the residual oil saturation from the swept zones that have been already swept by the preceding conventional waterflooding (secondary production). In this case the alkali solution reacts with the organic acids of the reservoir's crude oil (naphthenic acids) to form surfactants which in turn, have the ability to improve significantly the displacement efficiency of the residual oil. In the case of oil accumulations with low concentration in organic acids, a bank of oil rich in organic acids could be injected before the alkaline flooding. The mechanisms that target the already swept zones are **emulsification and entrainment** and **wettability reversal.**

In the second case alkaline waterflooding aims to decrease the relevant permeability of the already swept zones and to divert the waterflood that follows towards the unswept zones. This technique is more effective in highly viscous oils with high mobility ratios or in highly heterogeneous reservoirs. In some cases it is more profitably to recover the unswept oil formations that are less accessible than to target the limited quantities of the residual oil in the already swept – accessible zones. The mechanism that targets the unswept zones is **emulsification and entrapment.**

It is widely accepted that the reduction of IFT is a necessary but not a sufficient mechanism that could lead to a successful alkaline flooding. The increase in the recovery factor is attributed to synergy of low IFT, wettability alteration and the stability of the emulsions. [8] The oil displacement mechanisms which are encountered in alkaline flooding are presented below:

1. **Emulsification and Entrainment.**

In this mechanism the alkali of the flood water reacts with the crude oil acids (mostly carboxylic acids **R-COOH**) and as a result a surfactant is generated known as *soap*, which finally induces the reduction of the interfacial tension (IFT) between the residual oil and the floodwater. The amount of carboxylic acid that is contained in the crude oil determines the acid number of the crude oil. It is obvious that the efficiency of this mechanism depends largely on the acid number of the oil which in fact determines the amount of soap that can be produced in situ by the addition of specific amount of alkalis. Generally, carboxylic acids have low solubility in the aqueous phase at neutral pH and this is the reason why they are not extracted during conventional waterflooding. The concept of alkali flooding is to inject an alkali solution (pH > 7) which will react with the carboxylic acids and will generate a water soluble salt – emulsifier (soap). The emulsification results in the entrainment of the residual oil by the water flow and by this way the ultimate recovery factor is increased.

In **Figure 5.7** the mechanism of IFT reduction is illustrated. The group of carboxylic acids is represented as a single pseudo – acid component HA which is soluble in the aqueous phase at an extent and it is distributed between the oleic and the aqueous phase.

$$HA_o \leftrightarrow HA_w$$

The water soluble salt – surfactant A^- can be produced when carboxylic groups in the oleic phase HA_o react with the alkali solution NaOH as it is presented below:

$$HA_o + NaOH \leftrightarrow Na^+A^- + H_2O$$
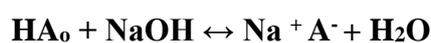
Another way to produce the surfactant A^- is by hydrolysis of the aqueous phase HA_w:

$$HA_w \leftrightarrow H^+ + A^-$$
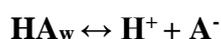
The existence of the alkali enhances the generation of the water soluble salt – surfactant A^- which is adsorbed at the oil – water interface and lowers the interfacial tension by a factor of several hundred. The alkaline concentration is determined by the extent of IFT reduction that is required. In oil accumulations where higher IFT

reductions are required a modified version of the technique could be implemented like thermal alkaline flooding or gas alkaline flooding.

2. Wettability Reversal (Oil-Wet to Water-Wet).

This mechanism can take place only in oil – wet reservoirs which demonstrate a continuous residual oil phase. The reversal of wettability to water wet results in a decrease of the residual oil saturation via two ways:

Firstly, the viscosity of the displacing fluid is increased which makes the mobility ratio to decrease and the phenomena of viscous fingering to be restricted.

Secondly, as the fluids are redistributed in the pore space, their attempt to return into their natural state make them more prone to displacement.

3. Wettability Reversal (Water-Wet to Oil-Wet).

The surfactants that are generated by the reaction of the alkali solution with the crude oil acids have the possibility under proper temperature, pH and salinity to change the wettability of the porous medium from water wet to partially oil wet. The reversal of wettability to oil wet results in a decrease of the residual oil saturation via two ways:

Firstly, the discontinuous residual oil droplets get connected with each other and form a continuous oil film which serves as a flow path enhancing by this way the oil displacement. Secondly, the wettability reversal to oil wet condition has as a result a significant increase in the pressure gradient in the pores. This induced pressure gradient in combination with the reduced capillary forces – reduced IFT (due to the alkali solution effect) make the residual oil to mobilize.

The wettability change either from oil wet to water wet or reversely from water wet to oil wet has as a result the increase in the recovery factor. In fact the more severe is the wettability change the higher the recovery efficiency becomes. [9] In **Figure 5.8** and **Figure 5.9** the wettability conditions of water wet and oil wet are illustrated. In water wet surfaces oil is at the center of the pores. The reverse is happening for oil wet surfaces.
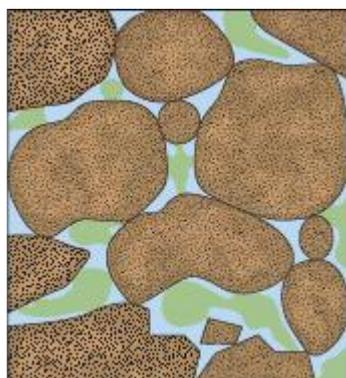
Figure 5.8: Water wet surface   **Figure 5.9:** Oil wet surface
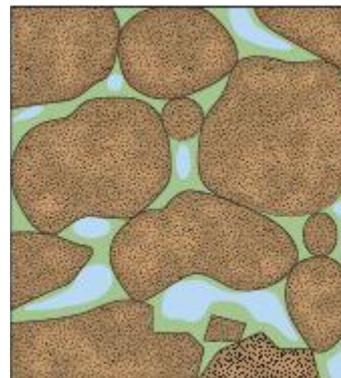
In **Figure 5.10** the two possible states of wettability are illustrated. Practically, the wettability of a surface in an oil – water system is measured via the contact angle θ between the rock surface and the tangent of the water phase. When θ<90° then the surface is considered to be water – wet. In contrast when θ>90° then the surface is considered to be oil – wet. Finally, when θ≈90° then the surface is characterised as neutral wet. The contact angle θ or in other words the wettability preference is actually determined by the competitive tendency of the immiscible fluids to spread in the rock surface. The nature of the rock is one of the basic parameters that define the wettability preference. For example quartz sandstones or calcite surfaces tend to be water wet. It must also be mentioned that the wetting character of the rock surface affects directly the capillary pressure forces, meaning the forces due to pressure difference between the interfaces.
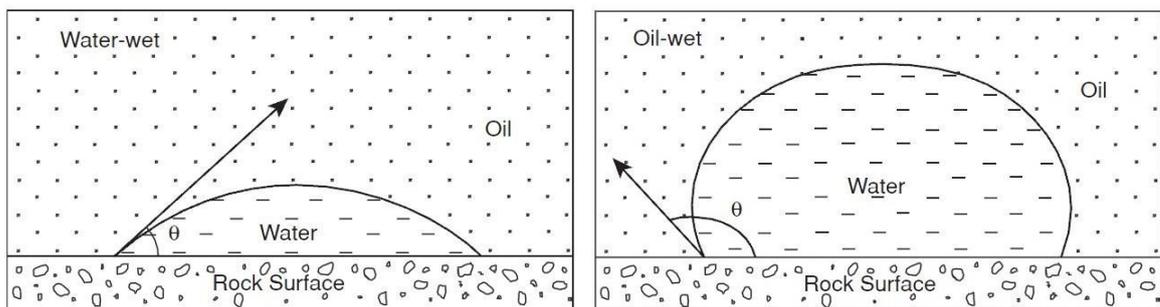
Figure 5.10: Water wet surface and Oil wet surface

4. Emulsification and Entrapment.

This mechanism aims at the formation of emulsion droplets which get incorporated in the flow stream and eventually decrease the permeability of the areas where they are driven, means the high permeability zones that have already been swept by the preceding water flooding. Subsequently, the water flood is diverted to the lower permeability – unswept zones and the overall sweep efficiency in increased. The entrapment mechanism which is illustrated in **Figure 5.11** is governed by capillary and viscous forces and is a function of the emulsion droplet to pore size ratio. There are two types of emulsion droplets as described below:
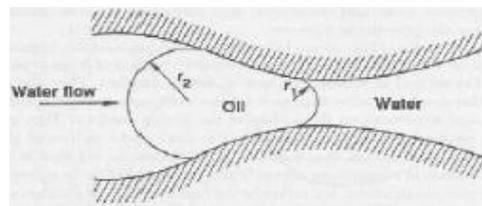
Figure 5.11: Entrapment mechanism

Water in oil (W/O) emulsion droplets are created when water drops are formed inside the oil phase. The alkali solution has the ability to penetrate in the residual crude oil and to form water drops inside the oil phase. As the alkali concentration in the injected solution increases, the number and the size of the water droplets in the W/O emulsion increases as well, resulting in higher volumetric sweep efficiency and subsequently higher recovery factors.
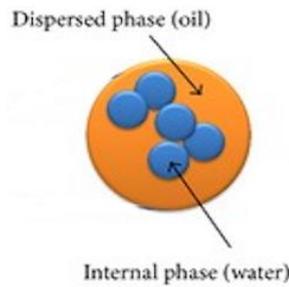
Figure 5.12: Water in Oil emulsion droplet

Oil in water (O/W) emulsion droplets are created by emulsification of the residual oil when the interfacial tension takes very low values. This mechanism is taking place mainly in water wet reservoirs. This type of emulsification is encountered especially in highly viscous oils.
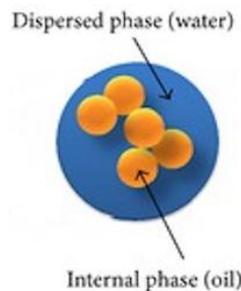
Figure 5.13: Oil in Water emulsion droplet

Generally, W/O emulsions coexist with O/W emulsions in an alkaline flooding with W/O emulsions to exhibit much larger stability than O/W emulsions. As the water cut in the emulsions increases then water becomes the continuous phase and W/O emulsions are converted into O/W emulsions. The value of the emulsion's water cut at which this conversion occurs it is known as critical water cut and depends on the type of chemicals used and their composition.

Advantages

The most important advantage of alkaline flooding is the relatively low cost of the technique and the fact that exhibits relatively good performance in highly viscous reservoirs or in reservoirs with high degree of heterogeneities.

When an alkali slug is injected, then the pH of the formation fluids is increased and a negatively charged environment is formed in the reservoir's pores. When flooding of an anionic surfactant is following the alkali slug then it becomes very beneficial that the reservoir rock surfaces are negatively charged because electrostatic repulsion will decrease the adsorption of surfactant in the reservoir rock surface.

Disadvantages

The decreased viscosity that characterizes the alkali slugs results in unfavorable mobility ratio between the displacing and the displaced fluid. Viscous fingering and decreased volumetric sweep efficiency are the main drawbacks of the technique that become more intense as the distance between the injector and the producer increases. The unfavorable mobility ratio, with all that entails and the difficulty in lowering sufficiently the interfacial tension result in very low incremental recovery factors around 2%.[4] For this reason alkaline flooding is always combined with other EOR methods that could be chemical, thermal or miscible gas injection methods.

The distance between the injectors and the producers is also limited due to the fact that the alkali concentration of the alkali slug is decreasing as it moves through the reservoir rock. The alkali reduction / consumption is attributed to the reactions of the alkali slug with the residual oil, the formation water and the reservoir rocks. For example, in **Figure 5.7** the reaction of alkali with the reservoir rock is illustrated that results in significant alkali consumption. More specifically, Na^+ are exchanged with H^+ ions which are found in the rock surface, to form water as it is presented in the chemical reaction below where X stands for an anion (non – metal) in the rock surface. To compensate for the alkali reduction, higher alkali concentrations than those calculated in the laboratories are recommended.

$$H\text{-}X + Na^+ OH^- \leftrightarrow Na\text{-}X + H_2O$$

Another drawback of the method is that all the metallic equipment in surface and down hole facilities that come in contact with the inorganic alkali solutions are subjected to significant corrosion. Stainless steel is recommended as a material for all the equipment that comes in contact with alkali solutions. Also, the cost of treatment of the production fluids is relatively increased due to the presence of high stability emulsions.

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Field application

Alkaline flooding is more suitable for heavy oil accumulations since they are rich in organic acids – necessary reactants for the formation of the desirable surfactants. Furthermore, it has been proved that interfacial tension at the oil – water surface decreases at higher rates as the oil becomes heavier. [7] Generally, this technique can be effective when applied in reservoirs containing oil with increased acid numbers.

Generally conventional alkaline flooding can be implemented in cases where IFT is less than 0.01 mN/m. [4] For higher values of IFT a modified version of the technique is required like thermal alkaline flooding or gas alkaline flooding or a combination with other chemical EOR methods

Alkaline flooding should not be implemented in carbonate formations (because of the abundance of calcium) or in sandstones with high clay content because of the increased alkali consumption. As it has already mentioned alkaline flooding do not demonstrate high incremental recovery factors over the conventional water flooding. The main drawback of the technique that does not permit to be applied separately is the

lack of mobility control. This is why alkaline flooding is always combined with polymer flooding.

Alkaline - Polymer flooding

In the alkaline – polymer flooding the aim is to combine the benefits of the alkalis (decrease of IFT, wettability alteration and emulsification) with the benefits of the polymers (improvement of the mobility ratio). Generally, this technique has been applied more in high viscous oil reservoirs. The combined polymer and alkaline flooding demonstrates the following properties:

1. It has been proved that the injection of an alkaline – polymer slug results in **increased displacement efficiency** when compared with individual polymer flooding or alkaline flooding. The increase in the viscosity that polymers bring result in better volumetric sweep efficiency. The injected slug can displace oil quantities that would be inaccessible in the case of individual alkaline injection. At the same time, alkaline displacement mechanisms improve the recovery efficiency of the accessed oil quantities further more.

2. The viscosity of the polymer solution decreases as the alkali concentration is increasing. This phenomenon could be very beneficial in low injectivity wells. As the polymer – alkaline slug is propagating in the reservoir, the alkali consumption make the solution's viscosity to increase again. By this way we have improved injectivity at the initial stages and improved sweep efficiency at the later stages of the slug propagation.

3. Alkaline polymer flooding results in decreased polymer adsorption and decreased alkaline consumption. The ability of the alkalis to charge negatively the rock surfaces result in a decreased rate of polymer adsorption. At the same time, as polymer covers inevitably, some parts of the rock surfaces the alkalis are consumed at lower rates.

In **Figure 5.14** the resulted residual oil recovery factors are illustrated for every possible combination and sequence of injected polymer and alkali slug injection. In **Figure 5.14** A/P represents alkali injection followed by polymer injection, P/A represents polymer injection followed by alkali injection whereas A+P represents the simultaneous polymer and alkali injection. Laboratory experiments on a coreflood verified that the best possible results come when polymers are injected simultaneously with alkalis (A+P). [10]
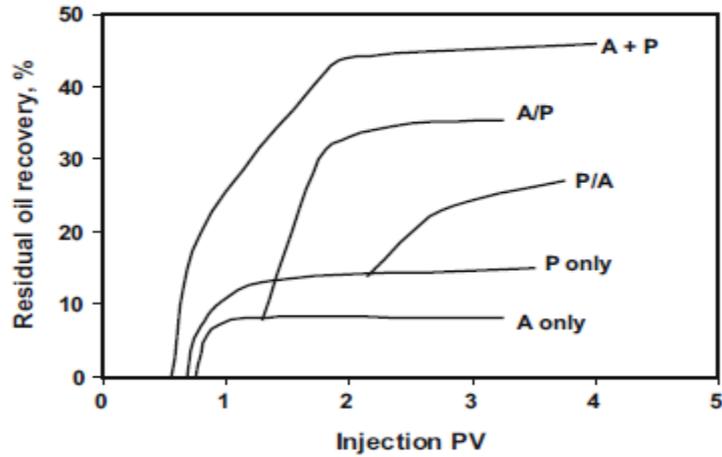
Figure 5.14: Coreflood residual oil recovery factors

In some cases it is recommended to inject firstly (preflush) an alkaline slug in order to take advantage of the emulsification and entrapment mechanism and to block the high permeability channels for the alkaline – polymer flooding that is following. This process is known as **CAT-AN** process. Also, in some cases polymer is injected after (post - flush) the alkaline – polymer flooding in order to prevent fingering phenomena of the water flooding that is following.

Till today there have been only height successful Alkaline – Polymer flooding projects worldwide and more specifically four at Canada, two in U.S.A. and two in China. All projects implemented in sandstone reservoirs. In most cases Na_2CO_3 was used as alkali and Synthetic (HPAM) as polymer. The average performance of the A-P projects is presented in **Table 5.2.** [10]

Table 5.2: Average values of the successful Alkaline – Polymer flooding projects

Incremental Recovery Factor	14%
Decrease in Water Cut	12.5%
Production cost / incremental bbl	1.7$/bbl
Polymer concentration	1.7% *
Alkali concentration	16.2% *

* It is the product of the injected slug in % percentage of the PV with the corresponding % percentage in concentrations of Alkali / Polymer in this slug

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5.5 Surfactant flooding
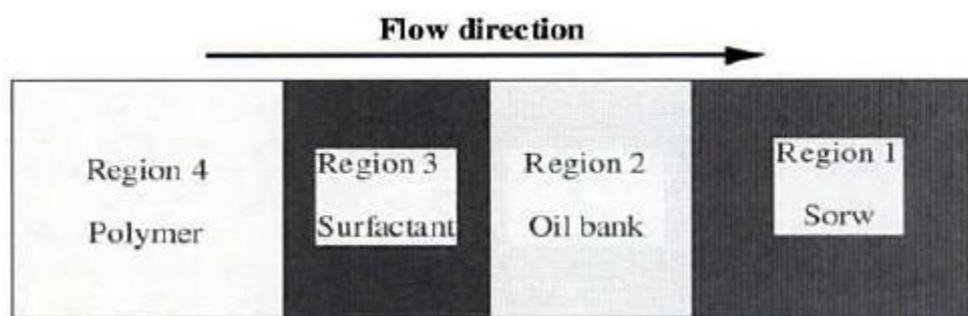
Figure 5.15: Polymer - Surfactant flooding

General description of the technique

The technique targets the residual oil quantities that remain capillary - trapped after waterflooding and manages to mobilize them by injecting surfactants capable to change the interfacial (water/oil) behaviour properties. The possible incremental recovery factor of the technique, ranges between 10% - 20% of the original oil in place. Generally, surfactant flooding is related with unfavourable mobility ratios which result in very low volumetric sweep efficiencies. In order to improve the rheological behaviour of surfactant flooding and make the technique commercially viable, it is compulsory to use polymers both in the surfactant slug and in the drive slug.

The word surfactant is derived from the words *surface* and *act* and refers to a blend of surface active organic compounds. In **Figure 5.16** general structure and the different types of surfactants are illustrated. It can be seen that all the surfactants are constituted by a tail which is a hydrophobic hydrocarbon chain and a head which is hydrophilic. The fact that surfactants are constituted by a hydrophobic and a hydrophilic part makes them to concentrate in the fluids interfaces in an attempt to decrease the free energy of the system. Surfactants are used in enhanced oil recovery because they have the ability to reduce significantly the interfacial tension (IFT) between the displacing and the displaced fluid. As a result of the decreased IFT the trapped oil quantities get mobilised and eventually form an oil bank. In **Figure 5.15** the discrete phases in a typical polymer – surfactant flooding are illustrated.

Surfactants are classified based on the ionic character of the hydrophilic group (head) as follows:

1. **Anionic surfactants** which are the most used since their adsorption in the negatively charged sandstone surfaces is minimised.

2. **Cationic surfactants** which can be used only in the positively charged carbonates. Generally they are more expensive than the anionic surfactants.

3. **Zwitterionic /Amphoteric surfactants** which are not used in the EOR processes.

4. **Nonionic surfactants** which are used in combination with the anionic surfactants to form a mixture with increased tolerance to salinity.
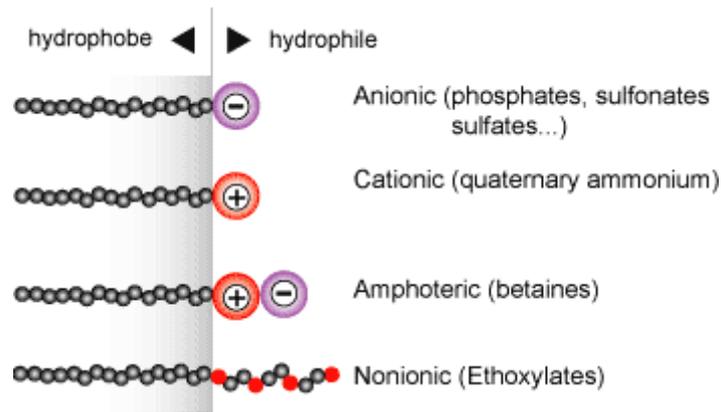
Figure 5.16: Types of surfactants

The oil displacement mechanism that surfactant flooding involves is **Reduction in Interfacial Tension (IFT).** As it has already mentioned, the surfactants are constituted by a hydrophilic head which has the tendency to be oriented towards water molecules and a hydrophobic tail which has the tendency to be oriented towards hydrocarbon molecules. This property of the surfactants makes them to concentrate in the water /oil interfaces where they interact and manage to reduce significantly the interface free energy meaning the interfacial tension.

In order to understand the importance of the interfacial tension reduction in the recovery of the residual oil quantities, the capillary number (N_C) must be introduced which correlates the viscous and the local capillary forces as it is described in a simplified form below:

$$\text{Capillary number: } \mathbf{N_C} = \frac{u * \mu}{\sigma}$$

Where:
u is the displacing Darcy velocity

μ is the viscosity of the displacing fluid

σ is the Interfacial Tension (IFT) between the displacing and the displaced fluid.

From the capillary desaturation curve that is presented in **Figure 5.17** it is obvious that in order to decrease the residual oil saturation the capillary number must increase. More specifically, the values of the capillary number which range around 10^{-7} after a typical water flooding must increase 1.000 or 10.000 times in order to achieve a considerable reduction in the residual oil saturation. From the definition of the capillary number N_C it can be seen that the only factor that has the possibility to affect so drastically the capillary number is the interfacial tension (σ) which can be reduced 1.000 or 10.000 times by the surfactants' interactions. It must also be referred that the decrease in the residual oil saturation leads, obviously to the increase of oil's relative permeability.
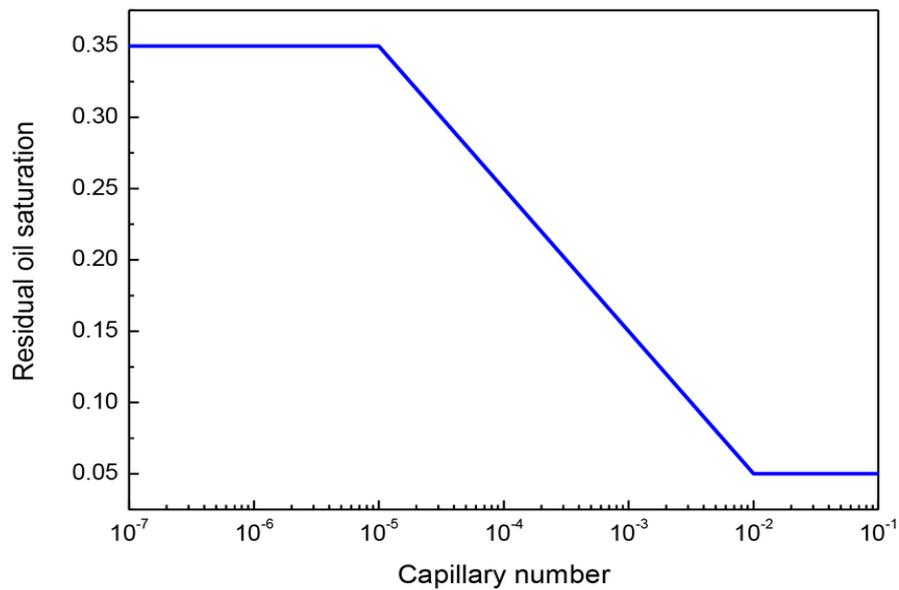
Figure 5.17: Capillary desaturation curve

In **Figure 5.18** the recovery mechanism of interfacial tension reduction is illustrated. In the left scheme the increased IFT does not allow the trapped oil quantities to flow whereas in the right scheme the injected surfactants have lowered the IFT which enables the oil quantities to overcome capillary trapping and flow through pore throats in order to agglomerate and form an oil bank. It is obvious that the lowering of IFT has caused the increase of relative permeabilities.
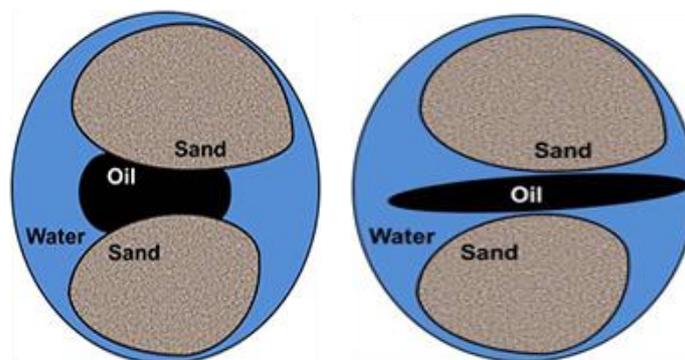
Figure 5.18: Reduction of Interfacial Tension (IFT)

Advantages

An accurate Surfactant – Polymer flooding process can result in ultra-low IFT between the displacing and the displaced fluid, making the technique the most effective for the displacement of residual oil quantities.

Disadvantages

Generally, surfactants are relatively expensive and in order to achieve substantial oil recovery significant amounts should be used making this technique largely dependent on the current oil prices. As it has already mentioned surfactants cannot be used individually but it is compulsory to use polymers both in the surfactant slug and in the drive slug. In order to minimize the transportation costs of the increased quantities chemicals it is almost necessary to install big storage tanks near the field. All the above constitute a serious constraint if the technique is to be implemented in large offshore fields. It must also be mentioned that chemical incompatibility between polymer – surfactant – brine may result to undesirable phase separation. The high cost of the surfactants in combination with the possible increased retention phenomena and the possible phase separation, raise significantly the economical risk of the EOR project.

Another basic disadvantage that prevents the implementation of the technique in shallow depths is the possibility of groundwater contamination with the highly toxic surfactants. Generally the cationic surfactants are more toxic than anionic or nonionic surfactants.

Field application: Surfactant - Polymer flooding

Generally, the design of a Surfactant – Polymer flooding can be characterized as a relatively complex procedure. The optimization process of a S-P flooding project attempts to increase as much as possible the oil recovery factor with the minimum possible surfactant losses due to retention and phase separation phenomena that occur in the reservoir.

It is a fact, that till today the vast majority of S-P flooding projects have occurred in the negatively charged sandstones due to the fact that the less expensive anionic surfactants can be used. Sandstones with high clay content must also be avoided due to the increased adsorption of the surfactants.

Several simulation studies have been conducted in order to identify the injection scheme and the salinity profile that leads to the highest recovery factor during a surfactant flooding. It must also be referred that by increasing the salinity of the system, the volume of microemulsion generated is increased which is favorable for the surfactant flooding process. After investigating negative and positive salinity gradients it has been proved that the optimum salinity profile should include: [11]

1. A pre slug with the optimum salinity

2. A surfactant slug with the optimum salinity

3. A post flush with salinity less than the optimum

The first pilot application of S-P flooding in China was implemented in the western part of the Gudong 7th reservoir and the results were very encouraging. The characteristics of the target zone were S-P flooding was tested are demonstrated at **Table 5.3**[16]

Characteristics of the target zone

Gudong 7th reservoir	
Depth of burial	1261 – 1294m
Av. Porosity	34%
Av. Permeability	1320 mD
Salinity of formation water	3152 mg/L
Viscosity of crude oil	45 cP
Reservoir Temperature	68 ºC
Reservoir Pressure	12.4 MPa

The target zone has been going through secondary production – water flooding since July 1986. In August 2003 before the start of the S-P flooding the daily oil production was 2.95 t/day whereas the average water cut of the 20 production wells was 98.3 %. The Recovery Factor was stabilised near 35.2% of the original oil in place.

In September 2003 S-P flooding was initiated via 10 injection wells and 17 production wells. The S-P flooding lasted till January 2010 and subsequently water flooding was implemented. The injection scheme involved four slugs, as it is presented in **Table 5.4** As it can be seen the total injected chemicals, accounted for 0.635 PV (Pore Volume of the target zone). More specifically, during the S-P flooding 5496 tones of polymers, 8727 tones of surfactants and 3024 tones of auxiliary components were injected. [16]

Table 5.4: Injection scheme of Surfactant - Polymer flooding in the Gudong field

	Starting Date	End Date	Polymer mg/L	Surfactant mg/L	Auxiliary mg/L	Slug size PV
Polymer pre slug	Sep 2003	May 2004	1934	0	0	0.078
S-P main slug I	Jun 2004	May 2007	1856	4618	1610	0.302
S-P main slug II	Jun 2007	Apr 2009	1713	3056	1043	0.188
Polymer post slug	Apr 2009	Jan 2010	1500	0	0	0.067

In conclusion, the S-P flooding in Gudong 7th reservoir was a successful project resulting in an incremental oil recovery of 16.7 % by December 2011 (ultimate recovery factor 51.9 %) whereas at the same time, water cut was decreased from 98.3% to 60.4%. [4] Till today 87 Surfactant – Polymer projects have been implemented worldwide, from which 74 are located in U.S.A. [11]

5.6 Factors affecting the efficiency of Surfactant flooding

Critical Micelle Concentration (CMC)

As it has already mentioned the surfactants have the tendency to concentrate in the water /oil interfaces and manage to decrease the interfacial tensions following the basic principle of minimising the system's free energy. As the concentration of surfactants in the injected solvent is increasing, the interface is covered by more surfactants and as a result the interfacial tension is decreasing inversely. The value of surfactant concentration in the injected solvent where the interface cannot accept more surfactants is called *Critical Micelle Concentration* (CMC). If we increase the surfactant concentration beyond the CMC value then the surface tension (or surface energy) is not decreasing furthermore but remains stable. Concerning the surfactants as they tend to minimise the system's free energy they start aggregating to form micelles as it is presented in **Figure 5.19.** In field implementations of surfactant flooding technique, the surfactant concentration in the injected solvent must exceed the CMC value due to surfactant retention phenomena that occur during the solvent's propagation in the reservoir. In surfactant slugs used in typical EOR projects Critical Micelle Concentration is achieved at surfactant concentrations around 10^{-5} - 10^{-4} mol/L [4] but as already explained, CMC point is always exceeded to encounter with the intense retention phenomena.

In a typical Surfactant – Polymer flooding the concentration of surfactants range between 0.1% and 2%. In an attempt to overcome the strong retention phenomena that S-P flooding involves, Micellar – Polymer flooding was investigated by several oil companies. M-P flooding involves the injection of a solvent with an increased surfactant concentration that range between 2% and 12%. Technically M-P flooding exhibits better field performance than S-P flooding, but the associated high cost due to the increased quantities of surfactants that are needed do not permit the technique to be economical viable.
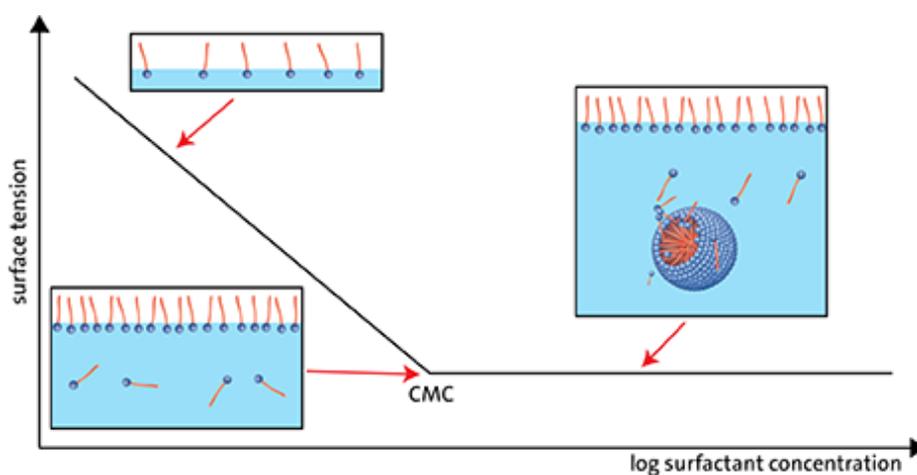
Figure 5.19: Interfacial tension as a function of surfactant concentration

Solubilization ratio

The most important factor that eventually determines the performance of a Surfactant - Polymer flooding project and eventually its economical viability is the phase behaviour of the surfactant / brine / crude oil system. During a typical water flood, a **water / crude oil** system is formed, in which the hydrocarbon non polar molecules do not interact with the polar water molecules. The increased interfacial tensions between the displacing and the displaced fluid dictate the immiscible displacement or in other words the phase separation, as the only state where the system can be thermodynamically stable, as it is presented in **Figure 5.20**
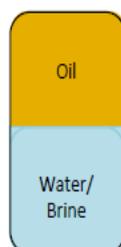
Figure 5.20: Thermodynamically stable water/ oil system during a waterflood

In the case of a surfactant slug injection then a **water/ crude oil / surfactant** system is formed. The phase behavior of this three component system is determined by the solubility of the surfactant in the water or in the oil phase and could be described by pseudoternary diagrams. The surfactant mixture could be:

- **Water soluble** meaning that the surfactants are attached to oil droplets forming aggregates or micelles which are spread in the continuous water phase forming an oil in water (o/w) microemulsion. This case is presented in the left side of **Figure 5.21**.

- **Oil soluble** meaning that the surfactants are attached to water droplets forming aggregates or micelles which are spread in the continuous oil phase water forming a water in oil (w/o) microemulsion. This case is presented in the right side of **Figure 5.21**.
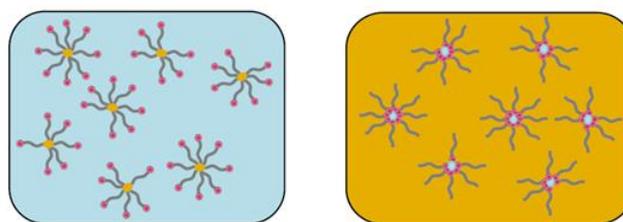
Figure 5.21: Types of microemulsions in a water/crude oil / surfactant system

The most important factor that eventually determines the solubility and subsequently the phase behavior of the water / oil / surfactant system is the salinity of the water. As the water's salinity is increasing the solubility is changing and it is possible to have three types of phase environments as it is illustrated in **Figure 5.22**:

- **Winsor I** type of phase environment. In low values of water salinity, surfactants exhibit good aqueous – phase solubility and very bad oil solubility. As a result

two distinct phases are formed: An oil in water (o/w) microemulsion phase and an oil phase. As the microemulsion is aqueous it is denser than oil and it accumulates below the oil phase. This is why it is also called lower phase microemulsion or (II-) type of microemulsion.

- **Winsor II** type of phase environment. In high values of water salinity, surfactants are driven out of the brine. As a result two distinct phases are formed: A water in oil (w/o) microemulsion phase and a water phase. As the microemulsion phase is oil external, it is lighter than water and it accumulates above the water phase. This is why it is also called upper phase microemulsion or (II+) type of microemulsion.

- **Winsor III** type of phase environment. In intermediate values of water salinity, surfactants exhibit similar oil –and aqueous phase solubility. As a result three distinct phases are formed: A water phase, an emulsion phase and an oil phase. The microemulsion is a mix of oil in water (o/w) and water in oil (w/o) microemulsions and for this reason is accumulated between the water and oil phase. This is why it is also called middle phase microemulsion.
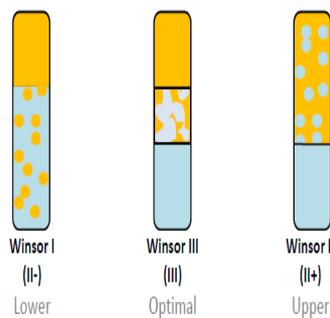
Figure 5.22: Thermodynamically stable microemulsions systems during surfactant flooding

The design of a surfactant flooding always aims to the formation and preservation of **Winsor III** type of phase environment. In this type of phase environment water is solubilised at the same extent with oil in the microemulsion, the resulting interfacial tension (IFT) between the water and oil phase is minimized which leads to practically miscible displacement and subsequently the recovery factor is miximised. The value of salinity concentration in the water that leads to Winsor III type of phase environment is called **optimum salinity**.

In order to demonstrate the significance of water salinity in the efficiency of surfactant slug injection several simulation experiments have been conducted. In **Figure 5.23** the solubility of water and oil in the microemulsion phase in various salinity concentrations is investigated. As Solubilization ratio or Solubilization parameter is defined the volume of oil (or water) that is solubilised in the microemulsion divided by the volume of surfactant in the microemulsion. So there is water solubilization ratio V_W/V_S and oil solubilization ratio V_O/V_S. As it can be seen from **Figure 5.23** water solubility (black line) is decreasing when salinity is increased. By contrast, oil solubility (red line) is increasing when salinity is increased. The optimum salinity is where equal amounts of oil and water are solubilised in the microemulsion phase. [12]
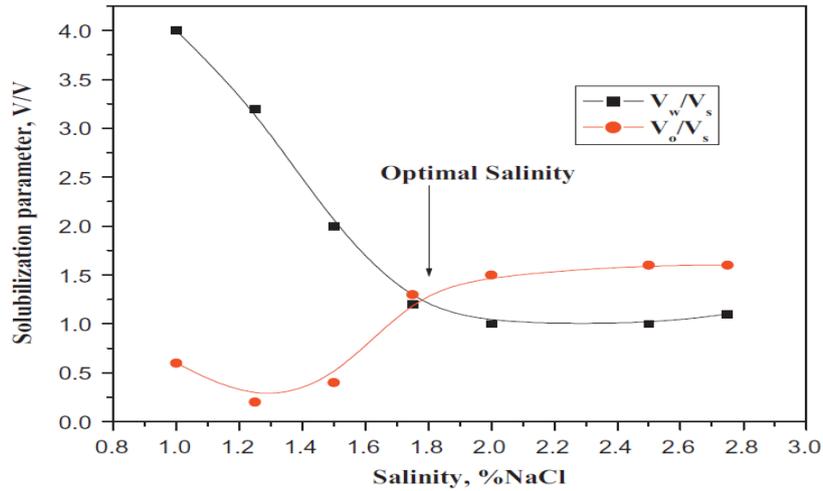
Figure 5.23: Solubilization ratio versus salinity concentration

In **Figure 5.24** it can be seen that the interfacial tension (σ_{mo}) between the oil phase and the microemulsion phase (black line) is decreasing when salinity is increased. By contrast the interfacial tension (σ_{mw}) between the water phase and the microemulsion phase (red line) is increasing when salinity is increased. It is obvious that the interfacial tension is strongly related with the solubilisation ratio and the microemulsion phase behaviour. In the optimal salinity both interfacial tensions demonstrate low values, miscibility between water and oil phase is approached and the oil recovery is maximized. [12]
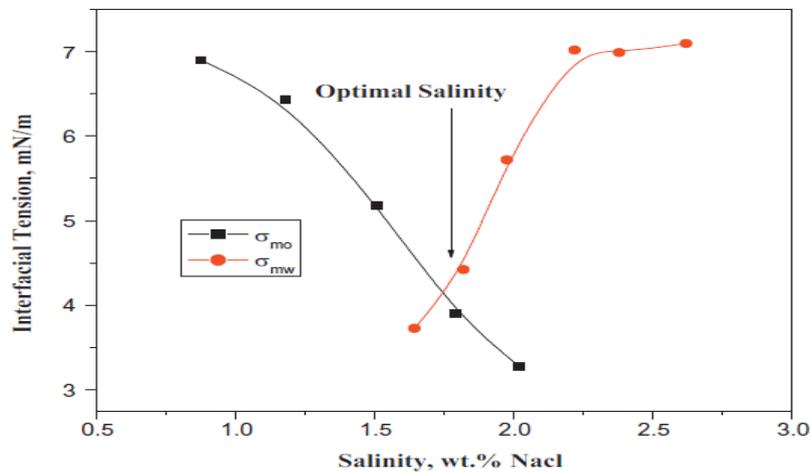
Figure 5.24: Interfacial tension versus salinity concentration

Surfactant Retention

The retention of the surfactant solution on the porous medium is occurring via the mechanisms of **adsorption**, **phase trapping** and **precipitation.** In a typical surfactant flooding, half or more of the total project's budget is determined by the cost of the surfactants. [13] So it is obvious that the intense of surfactants' retention phenomena will eventually constitute a deterministic factor of the economic success of the project.

1. **Adsorption**

This type of retention is attributed to the electrostatic interaction between the solid surface and the surfactants. It is a fact that most of the reservoir minerals exhibit a negative charge and this is the main reason why anionic surfactants are mostly used: to minimize the phenomenon of adsorption and the loss of material. The general trend is that adsorption becomes more intense as surfactant concentration in the slug is increasing, till a plateau is reached. A typical isotherm curve that describes the correlation between adsorption and surfactant concentration is illustrated in **Figure 5.25.** The shape of the isotherm curve may vary among different surfactant systems but generally the following four areas that correspond to different adsorption mechanisms are formed.
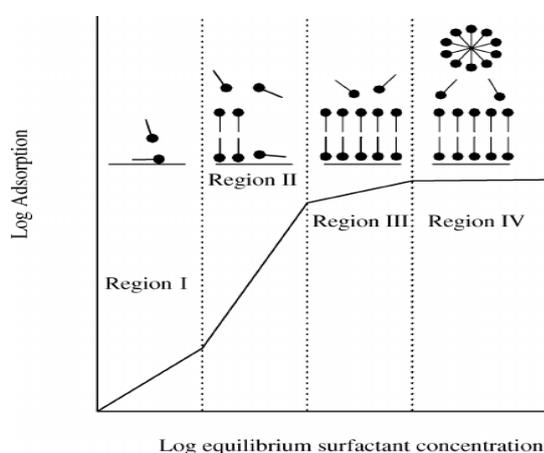
Figure 5.25: Typical surfactant adsorption isotherm

Region 1: In this area the adsorption increases linearly with surfactant concentration. The adsorption is attributed totally to attractive forces between the surface and the surfactants.

Region 2: In this area the adsorption increases at higher rate because of an additional adsorption mechanism. More specifically, the hydrophobic chains of the already adsorbed surfactants interact with the hydrophobic chains of the surfactants of the slug flow.

Region 3: Rock surfaces are not unilaterally charged at all their extent. In this example, when the positive charged areas are covered, then electrostatic repulsion is developed between the negative charged areas and the anionic surfactants. Furthermore the already adsorbed multilayer surfactants demonstrate negative charge at their edges that repulses the free monomers from the surface.

Region 4: If the surfactant concentration is increased more then the CMC point is reached and micelles are formed. Micelles do not absorb in the rock surface and as a result the adsorption process is ceased and a plateau is formed.

The main factors that have the possibility to influence significantly the extent of the adsorption process are salinity and acidity as described below:

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Salinity: An increase in the salinity of the system results in an increase in the adsorption capacity of the adsorbent surface. This is because salt quantities are deposited on the already adsorbed multilayer surfactants decreasing by this way the developed repulsive forces, a mechanism that as it has already been mentioned is present in Region 2 and especially in Region 3 of the surfactant adsorption isotherm, **Figure 5.29.**

Acidity: Concerning anionic surfactants, the adsorption efficiency of the adsorbent surface is decreasing significantly by increasing the PH value of the aqueous solution. As it has already been mentioned a preflush of an alkali slug is often injected to increase the PH of the formation fluid. By this way a negatively charged environment is formed in the reservoir's pores reducing by this way the adsorption of surfactants. As far as non ionic surfactants are concerned, the adsorption efficiency is decreasing by increasing the PH value up to neutral PH. For higher (alkaline) values of PH adsorption capacity remains relatively stable. Obviously the adsorption behaviour mentioned is related to negatively charged rock surfaces (sandstones) which are the most usual case.

2. Phase trapping

This type of retention is related to multiphase flow and it is more intense when Winsor II micro emulsions are formed. As it has already mentioned, Winsor II micro emulsions phase are oil external which means that is lighter and more viscous than water. This could possible result in the bypass of the microemulsion phase from the water flood that follows and subsequently in phase trapping. It is obvious that phase trapping is less intense in Winsor I micro emulsions phase which are water external and miscible conditions could be approached during displacement by the water flood that follows.

3. Precipitation

This type of retention can limit drastically the effectiveness of a surfactant flooding especially in aqueous environments which demonstrate high values of salinity. Before the surfactant flooding, pre – flushing is often used in order to lower the salinity of the formation water. Another possible way to increase the tolerance of the surfactant slug is to use non ionic surfactants in conjunction with the anionic surfactants, as a mixture. In the surfactant slug a component system is formed, as it is presented in **Figure 5.26** which is consisted of the following components in equilibrium:

Micelles: As it has already been mentioned, the injected surfactant concentrations always exceed the CMC point. This is why micelles are formed. As we can see the micelles are mixed and they are consisted by anionic and non ionic surfactants. At their surface some counter ions may be attached.

Anionic surfactants: They can exist as monomers, aggregated in micelles or precipitated in the form of salts. It has been proved that when using a multi component mixture of anionic surfactants instead of a single type deceleration of the precipitation process can be achieved for the same surfactant concentrations. [14]

Non ionic surfactants: They are added in order to reduce the anionic surfactant concentration in the micelles and by this way to increase their salinity tolerance. It has been proved that the salinity tolerance of a surfactant system is increasing as the percentage concentration of the non – ionic surfactants is increased. [15]

Counter ions (Cations): The salts of the reservoir rock are dissolved in the surfactant solution providing it with counter ions like Sodium ions Na^+ or Calcium ions Ca^{2+}. A precipitation phase boundary (salinity tolerance of the surfactant system) is determined which delimits the concentration of counter ions above which surfactant precipitation occurs.

Precipitates: The anionic surfactants react with the counter ions to form salts which precipitate at the rock surface.
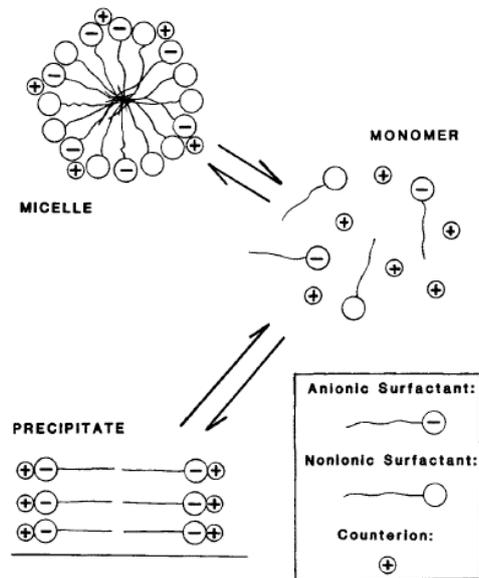
Figure 5.26: Equilibrium in a surfactant mixture

Surfactant Degradation

Generally, surfactant degradation refers mainly to biodegradation and it is not desirable during surfactant flooding, as the quantity of the available surfactants is decreased. Nevertheless biodegradation can be beneficial after surfactant flooding as surfactant accumulation in the subsurface environment is avoided and subsequently the possibility of ground water contamination. It must be mentioned that high values of surfactant concentration in the injected slug restrain significantly biodegradation process. Generally, during a typical surfactant flooding, there is the undesirable biodegradation at the front of the flood where surfactant concentration is low and the desirable biodegradation of the surfactant quantities that are left behind the displacement front.

5.7 Alkaline Surfactant Polymer (ASP) flooding
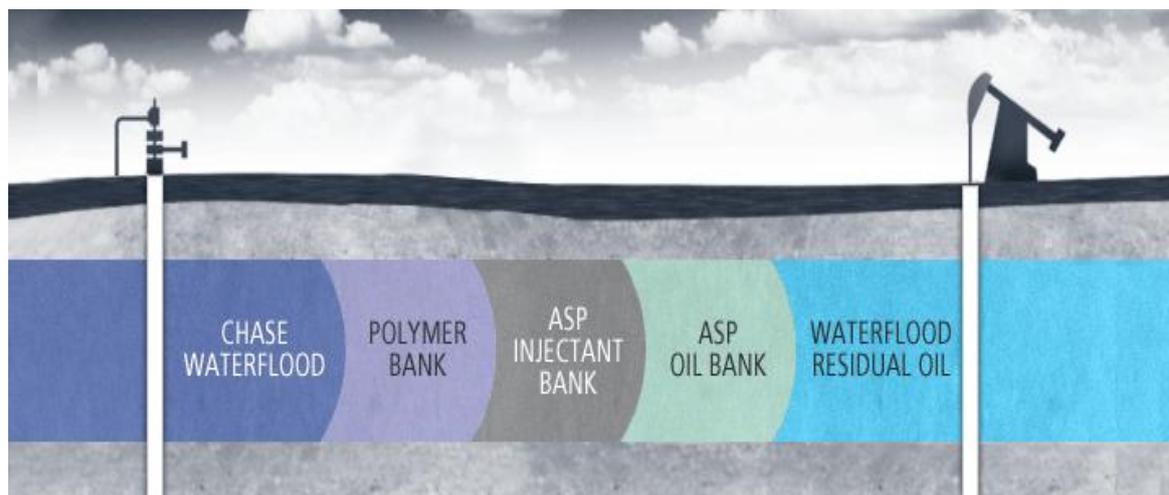
Figure 5.27: Alkaline Surfactant Polymer flooding

General description of the technique

The technique aims to the synergic effect of the different displacement mechanisms of Alkalis, Surfactants and Polymers which allow achieving higher displacement efficiencies and subsequently higher recovery factors. Numerical simulations have proved that the synergic effect of ASP flooding can result in higher ultimate oil recovery factors than any other combination of one A, S, P or two components AS, AP, SP chemical flooding for the same volume of injected chemicals. Just to have an order of magnitude the incremental oil recoveries via ASP flooding usually vary between 23 − 33% of the oil originally in place (over the conventional water flooding). [17]The interactions between the ASP components which result in the desirable synergy are presented, summarily below:

Alkalis

As it has already been mentioned, alkalis increase the PH of the formation fluid, the negatively charged density of the rock surface is increased and subsequently the adsorption of the anionic surfactants is decreased. By adding alkalis, the loss due to adsorption of the most expensive surfactant component is decreased significantly.

During the recovery mechanism of emulsification and entrainment, that has already been mentioned, alkalis react with the acids of the crude oil and a surfactant is generated known as soap which reduces the IFT. Moreover, the soap generated forms a microemulsion phase which actually broadens the optimal salinity range and subsequently the range of the desirable Winsor III type of phase environment. By this way the effectiveness of the surfactants in lowering the IFT in enhanced.

It must be mentioned that the effectiveness of the alkalis fraction in an ASP flooding depends largely on the acid number of the crude oil. A minimum concentration limit could be set 0.3 mg KOH/gr of crude oil. [4]However, in crude oils with low acid number, alkalis may be added to the injected slug just to reduce the surfactants' adsorption.

Surfactants

By adding surfactants ultra-low IFT is achieved, trapped oil gets mobilised and subsequently oil banks are formed. Surfactants also minimise the possibility for the mobilised oil quantities to get trapped again. They are very effective in lowering the IFT but also they are much more expensive when compared with alkalis or polymers. It is very crucial for the economic viability of an ASP flooding project to limit as much as possible the retention phenomena of the surfactants.

Polymers

The addition of polymers is absolutely necessary when using surfactants or alkalis as by increasing the slug's viscosity, the mobility ratio and subsequently the volumetric sweep efficiency are improved significantly. Without the addition of polymers in the injected slug surfactants and alkalis are in fact ineffective.

The phenomenon of adsorption in the rock surfaces is related with the polymers and the surfactants as well. As a result the two chemical components are competing with each other for specific rock surfaces. By adding polymers, the loss due to adsorption of the most expensive surfactant component is decreased significantly.

As it has been mentioned, the addition of polymers increases the viscosity of the ASP slug. This has as a result the stabilisation of the W/O or O/W emulsion droplets that are created by the alkalis action because due to higher viscosity their coalescence is retarded. By this way the effectiveness of the emulsification and entrapment mechanism is enhanced and the volumetric sweep efficiency is improved.

Advantages

The synergic effect if ASP process can lead to the highest displacement efficiencies and recovery factors when compared with the other chemical EOR methods. Also, ASP flooding demonstrates good economics as alkalis and polymers are relatively inexpensive chemicals whereas the adsorption and the loss of the more expensive surfactants is minimised.

Disadvantages

The basic disadvantage of the method is its sensitivity to the well – spacing. Generally the ASP flooding demonstrates very high displacement efficiency in a radius that could extend around 50 m from the injection well. Beyond this distance it is very likely that the integrity of the chemical slug will be disrupted and the displacement efficiency will be decreased, especially in reservoirs with high degree of heterogeneities.

One disadvantage of the method is the increased requirement for surface facilities as alkalis, surfactants and polymers must be stored separately. Also a unit is needed for ASP preparation and water treatment. Water must be softened in order to achieve full compatibility with the ASP components.

The presence of alkalis in the ASP flooding results in chemical reaction of the slug with the napthenic acids of the crude oil. The salts / inorganic precipitates / scale that are produced decrease significantly the formation's permeability. This formation damage results in well plugging – loss of productivity in the production wells and loss of injectivity (that could reach 25%) in the injection wells. In cases where the formation's permeability is relatively low, in order to minimise the inorganic precipitations a weaker alkali may be used or an alkali free flooding (SP).

Downhole metallic surfaces are subjected to corrosion. In order to protect the wells corrosion inhibitors compounds should be added in the injected slug.

Field application

As it has already been mentioned, the higher displacement efficiency that ASP flooding demonstrates is attributed to the synergy effect of its chemical compounds. The ASP flooding design should result in the simultaneous movement of the three components and prevent as much as possible their separation. Generally, the concentration of each component in the slug is decreasing as the slug is proceeding based on each component's retention and consumption phenomena. The only parameter, through which the undesirable separation issue could be regulated at an extent, is the calibration of the injected concentrations of each component.

The majority of ASP flooding projects have taken place in China, but there have been some implementations in U.S.A. and in Canada as well. Despite of the fact that the technique exhibits very high potential for increased incremental recovery factor the difficulty to preserve the integrity of the chemical slug did not allow ASP flooding to be commercialised   at a big extent. It should also be referred that till today there is no a successful ASP flooding implementation in a carbonate reservoir.

A successful ASP flooding has been implemented in the Cambridge field which is located in Crook County, Wyoming, U.S.A. The reservoir's characteristics are demonstrated at **Table 5.5**[4]

Table 5.5: Characteristics of the reservoir

Cambridge field	
Depth of burial	2139 m
Av. Porosity	18 %
Av. Permeability	834 mD
Density of crude oil	20 °API
Viscosity of crude oil	31 cP
Reservoir Temperature	55.6 °C
Reservoir Pressure	1792 psi
Formation Volume Factor (B_O)	1.03

The injection scheme of the ASP flooding is presented in **Table 5.6.** As it can be seen waterflooding lasted only for 1 month before the start of ASP flooding. This is a case where an EOR method is implemented for secondary recovery. As alkali Na_2CO_3

was used in the ASP slug, as surfactant Petrostep B-100 and as polymer Alcoflood 1275 A.

Table 5.6: Injection scheme of Alkaline – Surfactant – Polymer flooding in the Cambridge field

	Starting Date	End Date	Alkaline wt. %	Surfactant wt. %	Polymer mg/L	Slug size PV
Water injection	Jan 1993	Feb 1993	0	0	0	-
ASP slug	Feb 1993	Sep 1996	1.25	0.1	1475	0.252
Polymer post slug	Oct 1996	April 2000	0	0	-	0.244
Water injection	May 2000		0	0	0	-

The total period of ASP flooding was approximately 89 months. The ASP project resulted in an ultimate oil recovery factor of 60.9 % of the original oil in place when the numerical simulations were estimating the ultimate recovery to be around 34.1% if waterflooding had been implemented. [18] It must be mentioned that it has not yet proved whether the incremental recovery factor should be attributed to the improvement of the sweep efficiency due to the polymer injection or it should be attributed to the synergic effect of the ASP flooding. Nevertheless, in the production period of ASP flooding 1.143 million bbls of oil have been produced at a total cost of $ 2,767,000. The total cost of the purchase of chemicals was $ 2,518,000. In **Table 5.7** the cost per volume unit of the chemicals used, is presented. The cost for the chemicals storage and water treatment equipment was $ 160,000 and finally the pumping and maintenance costs were $ 1000 per month meaning $ 89,000 for the entire period. Subsequently the cost of each incremental barrel of oil was configured at 2.42 $ /bbl. [4]

Table 5. 7: Cost per volume unit of the chemicals used in the project

	Alkali	Surfactant	Polymer
Cost	0.12 $ /lb	2.00 $ /lb	1.20 $ /lb

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Chapter 6 Current status of EOR methods

6.1 EOR Potential

Generally, EOR techniques can be applied to medium – large fields with considerable quantities of oil in place which can justify the major investment that include. The world's average recovery factor after primary and secondary production techniques ranges around 40%. That means that globally, the biggest percentage of the reservoirs' identified oil, with existing infrastructures, cannot be produced without the implementation of a suitable EOR technique.

The potential of EOR methods means the oil quantities that remain in the reservoir after primary and secondary oil recovery methods are calculated to be near $2 * 10^{12}$ barrels of conventional light oil and near $5 * 10^{12}$ barrels of heavy oil and oil from other, unconventional reserves (oil from oil sands, shale oil and tight oil). In total the world EOR potential is calculated to be nearly **$7 * 10^{12}$ barrels of oil** (2008 data). [1]

In **Figure 6.1** the fluid saturations and the target oil quantities for each type of oil are illustrated. In the conventional oil reserves EOR techniques are applied after primary and secondary production where at least 45% of the OOIP is left behind. However, it has been proved that when EOR techniques are applied in the early stages of a field development (before the end of secondary production) then the ultimate oil recovery is boosted and generally the economics of the project are improved. Concerning the unconventional oil reserves, EOR constitute the only way to be exploited as they demonstrate very little response to primary and secondary production techniques.

(Assuming Soi = 85% PV and Sw = 15% PV)
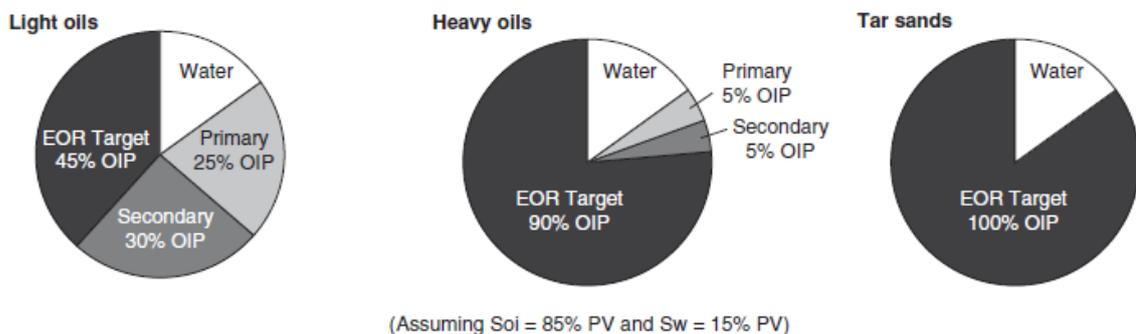
Figure 6.1: EOR target for different types of oil

6.2 EOR world distribution

In **Figure 6.1** the world distribution of successfully implemented EOR projects till 2010 is illustrated. [2] As it can be seen the leading country in Thermal and Miscible flooding EOR projects is U.S.A. whereas the leading country in Chemical EOR methods is China. Canada and Venezuela have also a significant number of commercially viable EOR projects.
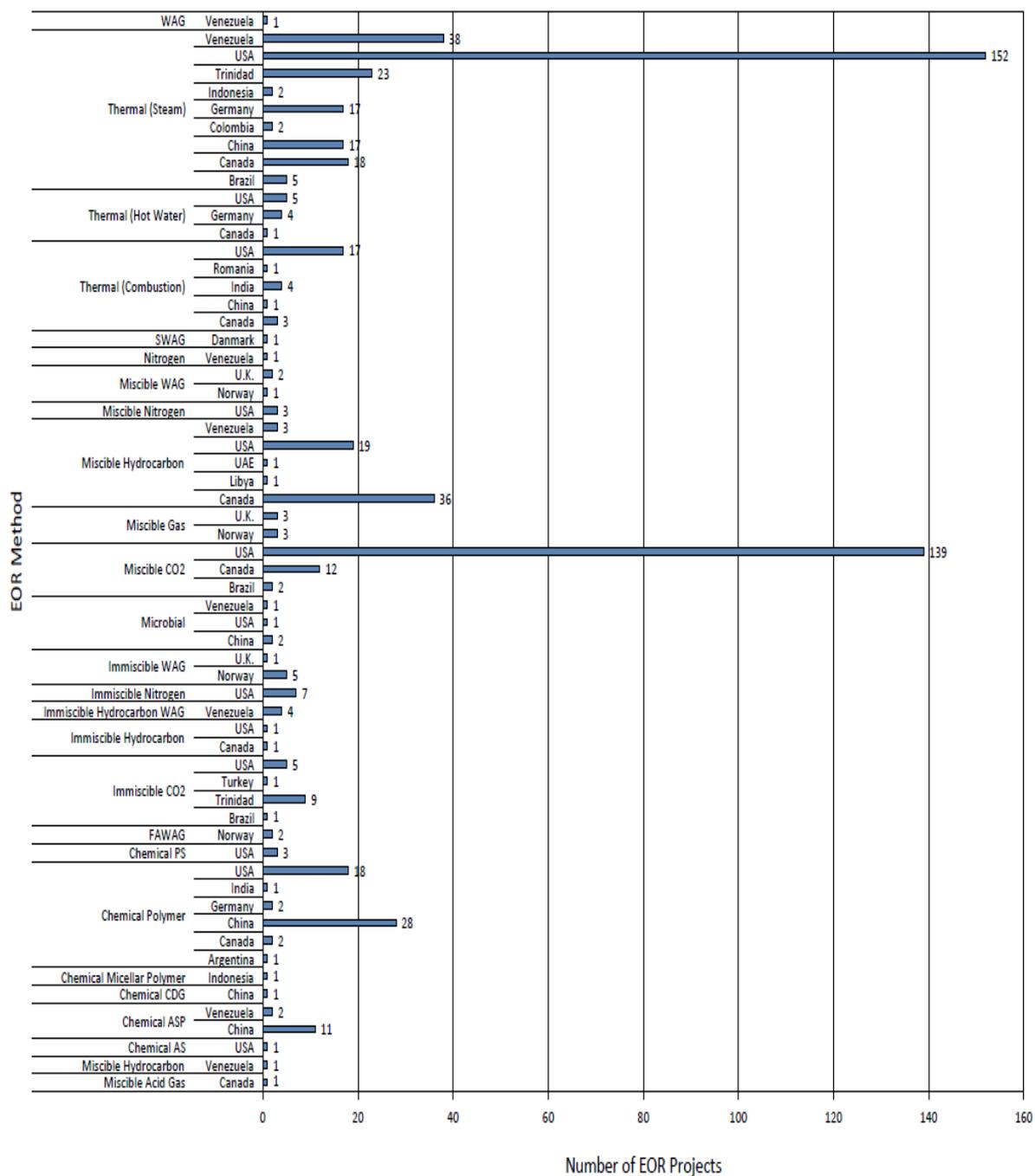
Figure 6.2: EOR world distribution

6.3 EOR technological maturity distribution

In **Figure 6.3** the technological maturity of each EOR method is illustrated. As it can be seen Thermal and Miscible flooding EOR methods are classified as mature enough to ensure a commercially viable implementation. Concerning the Chemical EOR methods, Polymer flooding exhibits the highest reliability whereas the rest of the techniques require further development. Finally, Microbial and Foam Injection EOR methods are in the early stages of the research and development phase.

The technological maturity of each EOR method can be identified from **Figure 6.2** as well, where the number of commercially successful EOR projects for each method is illustrated. As it can be seen the most widely used Thermal EOR techniques are those related with steam injection but in – situ combustion methods have a significant contribution as well. Concerning the Miscible flooding techniques the most of the applications are based on CO_2 injection followed by natural gas injection techniques. Finally, Chemical EOR methods seem to have been implemented successfully in a relatively small number of EOR projects most of which are Polymer and ASP floodings.

Generally, technological advances manage to increase the efficiency, to abolish some of the limitations and to broaden the number of possible oil fields where EOR could be applied. It should be mentioned that the development of an EOR technology so as to reach its maturity stage is a very time demanding procedure. In order to apply and evaluate a pilot field test of an EOR technique, laboratory tests, geological studies, reservoir simulation, implementation of the technique and anticipation for the field's response in the form of incremental oil production should be conducted.
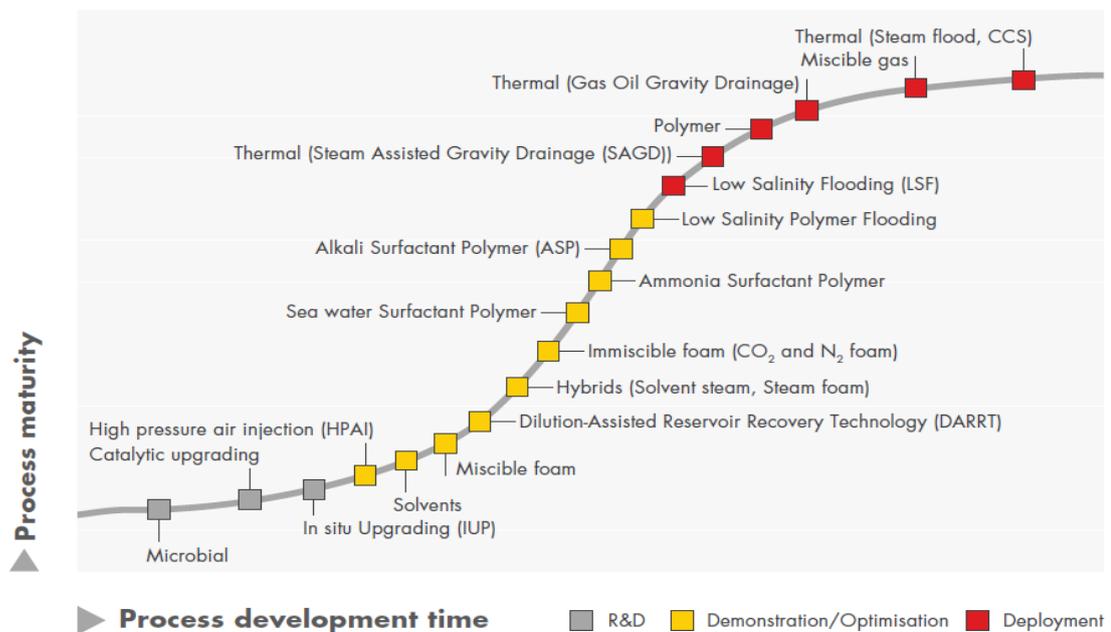
Figure 6.3: EOR process maturity

6.4 EOR market share
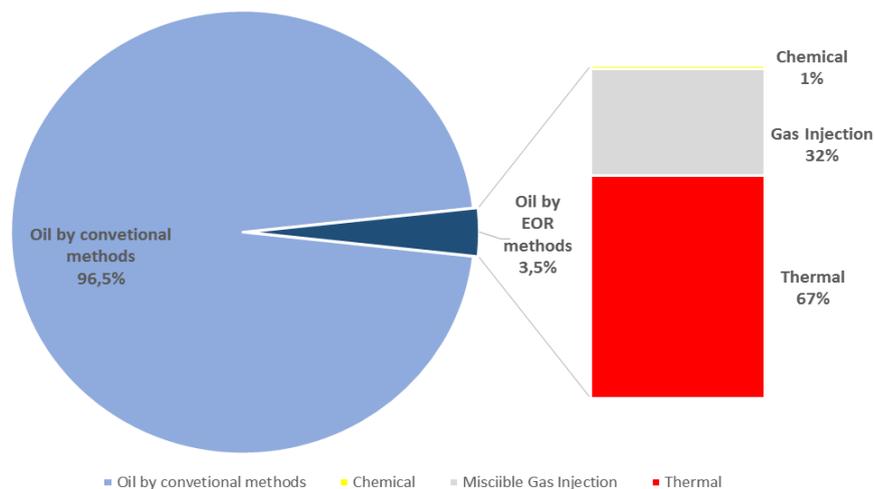
Figure 6.4: Global daily oil production share

According to the article Enhanced oil recovery challenges & opportunities that was published by the World Petroleum Council [3] around 3,5 % of the global daily oil production (2010 data) was provided by Enhanced Oil Recovery methods (3 million barrels of daily production out of the total ~ 85 million). As it can be seen from **Figure 6.4** the majority of the enhanced oil production relies on the Thermal EOR projects. Miscible Gas Injection contributes with around one third in the total EOR production whereas chemical EOR methods have the lowest market share with a contribution around 1%.

The main reason that Thermal EOR implementations outnumber the other EOR methods is because they have the possibility to be applied as a primary, secondary or tertiary recovery stage. In other words, EOR methods have the potential to be implemented in a wide range of oil saturation levels. Concerning Miscible Gas Injection EOR methods, are used as a secondary recovery method. Finally, Chemical EOR methods are implemented after water flooding as a tertiary recovery method. In **Figure 6.5** the estimation about the global EOR market volume is illustrated according to *Grand View Research* [4]. It is obvious that global EOR market is expected to grow significantly with the Miscible Gas Injection methods to face the biggest increase of all the other EOR methods.
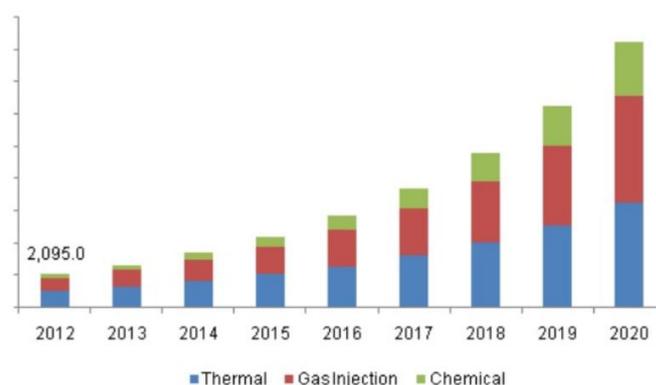
Figure 6.5: Global enhanced oil recovery market volume (Million barrels)

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Part B

Investigation of EOR implementation on Gullfaks oil field

Chapter 1 Introduction

1.1 Gullfaks oil field

Figure 1.1: Gullfaks oil field

Gullfaks oil field is found on the Norwergian side of the North Sea as it is illustrated in **Figure 1.1** and more specifically in the block 34/10. It can be characterised as a mature oil field as its peak oil production have been already reached at 7 Oct 1994 (605,965 bbl / day). The produced oil is transferred via shuttle tankers whereas the associated gas is transferred to a treatment plant on the land via pipelines. The production of the field is conducted by Statoil and is based on three offshore platforms as it is presented in **Table 1.1**: [1]

Table1.1: Platforms of Gullfaks oil field

Gullfaks oil field			
Offshore Platform	Gullfaks A	Gullfaks B	Gullfaks C
Production Start	22 Dec1986	29 Feb 1988	4 Nov 1989

The expected ultimate recovery factor at the start of the production had been estimated to reach 46.5 %. Because of a good depletion strategy and because of modern production techniques that have been implemented like horizontal drilling, extended – reach wells, water alternating gas injection (WAG) the ultimate recovery factor at 2012 was estimated to be 60%. Statoil is investigating the implementation of EOR techniques in order to increase the ultimate recovery factor of the field at 70%. [2]

Gullfaks oil field is consisted by the Gullfaks main field which is surrounded by several smaller satellite fields. Gullfaks main field contains 78% of the OOIP and 88% of the recoverable reserves. The satellite fields which are controlled by the previously mentioned platforms are: Gullfaks South, Skinfaks, Rimfaks and Gullveig.

Gullfaks is an offshore oil field and subsequently, exhibits the following general characteristics:

- Large well spacing.

- The available water for injection is of high salinity as it is provided by the sea.

- Limited available space on the platforms

- The production water is released to the sea

In addition, Gullfaks oil field exhibits the following features which should take into careful consideration before applying a possible EOR method:

- The structural geology in the Gullfaks main field is complex and includes large number of faults which set the limits of many sealed - independent oil bearing segments. The production characteristics differ at each segment resulting in different recovery factors. Moreover the complex structural geology decreases the quality of the seismic resolution and subsequently the resulting well trajectories may differ from the optimum ones.

- The reservoir's permeability is extremely heterogeneous. Consequently, water flow goes though the most permeable zones. Fingering phenomena become intense which result in very low volumetric sweep efficiencies, high water cuts and increased residual oil saturations.

- The field is mature and the production is gradually decreasing. The largest percentage of mobile oil has already been produced and what is left is the immobile oil.

- Sand particles that are poorly consolidated get easily detached from the reservoir rock and are drifted from the water flow resulting in damages in the production equipment. The increased sand content in the fluids flow limits the production rate to a level where the equipment is not damaged.

- Increased H_2S production which resulting in corrosion of the production equipment and in deterioration of the working environment of the platform.

The current simulation study for the investigation of the use of EOR methods refers to the H1 segment of the Gullfaks main field. Nowadays, the oil production of H1 block is based on the secondary production technique of waterflooding with the moderate microscopic and macroscopic displacement efficiency that involves.

1.2 Geology of Gullfaks oil field
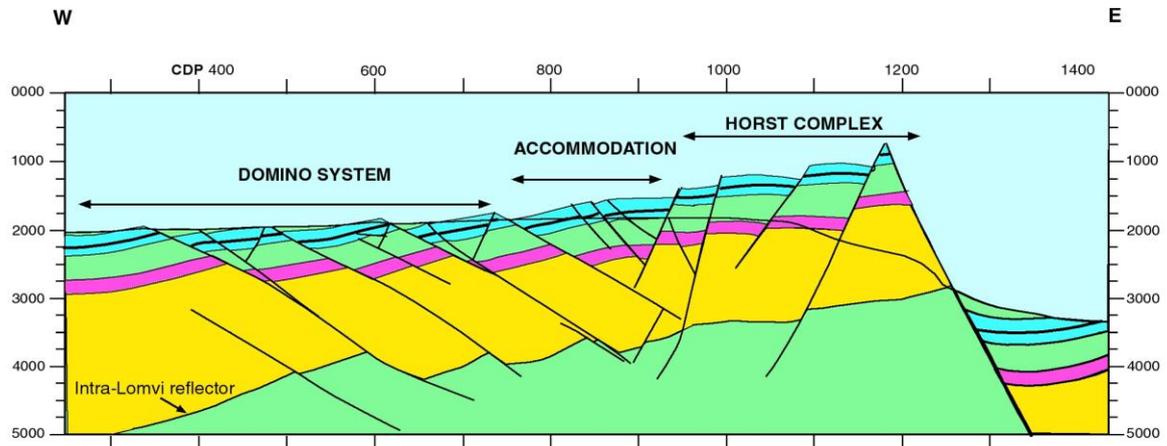
Figure 1.2: Structural map of Gullfaks oil field

Gullfaks is an oil field that is characterised mainly by its complex fault pattern. The fault pattern is illustrated in **Figure 1.2** It can be seen that three different fault systems are formed in the field. There is the *Domino System* with parallel faults dipping from west to east. In the middle of the field there is an *Accommodation Area* and to the east there is a *Horst Complex.* [3]

From the structural map in **Figure 1.2** it can be seen that the complex fault pattern of the reservoir, manages to form several isolated segments. It should be mentioned that a segment is considered to be isolated when there is no pressure communication or fluid flow to / from the surrounding segments.

The Gullfaks oil field is consisted by four stratigraphic oil - bearing formations that are separated by different colours in **Figure 1.2** and are mentioned bellow in increasing depth of burial. It should be mentioned that these formations are isolated from each other.

1. **Brent Group** (on the top – blue area)

2. **Cook** (green area)

3. **Statfjord** (purple area)

4. **Lunde** (on the bottom – yellow area)

In **Table 1.2** the status of the four stratigraphic formations that consist Gullfalks's oil field is presented. In **Table 1.4** a detailed status of all the Gulgaks' segments is illustrated. As it can be seen Brent Group formation is the most important as it contains 73% of the OOIP. It has been deposited in a river delta system during the mid – Jurassic period. [3]

Status of Gulfaks' stratigraphic formations

Gullfaks oil field			
	STOOIP (MSm^3)	Cumulative Production (MSm^3)	Recovery Factor (%)
Brent Group	440	278.3	63.25
Cook	60	17.85	29.76
Statfjord	93	54.61	58.72
Lunde	6	0.52	8.75
Total (2011)	599	351.3	58.65

In **Figure 1.3** the stratigraphic column of the whole Gullfaks oil field is illustrated. Every single segment of the Gullfaks oil field is consisted by the four previously mentioned reservoirs means Brent Group, Statfjord, Cook and Lunde which are isolated from each other. The present simulation study will focus on the isolated H1 segment of the Lower Brent Group. In **Table 1.3** the relevant stratigraphic position of H1 Segment is illustrated. As it can be seen H1 Segment consists of three reservoirs which are isolated from the Cook formation below and from the Upper Brent Group above. The vertical isolation of H1 segment is illustrated in **Figure 1.3** where it can be seen that in the lower and upper part of Lower Brent Group there are areas of zero permeability. More specifically H1 Segment is constituted by the following reservoirs: [2] [4]

- **Etive** reservoir exhibits very good properties. It is consisted of large grain size sandstones. The size of the grains makes the permeability to vary from 20 mD to 5000 mD. The porosity of the formation is around 33 %

- **Rannoch** reservoir is consisted of sandstones and can be characterized as moderate – good reservoir. The reservoir's porosity is around 11% at the bottom whereas at the upper parts it gets similar to Etive's means 33%. Concerning the permeability is around 10 mD at the bottom and increases to around 1000 mD to the upper layers.

- **Broom** reservoir is of minor importance for the oil production as it is very thin.

Table 1.3 : Reservoirs of Brent Group and H1 Segment

Brent Group	Upper Brent Group	Tarbert	50m	
		Ness	90m	
	Lower Brent Group	Etive	22m	**H1 Segment**
		Rannoch	70m	
		Broom	6m	
Cook formation				
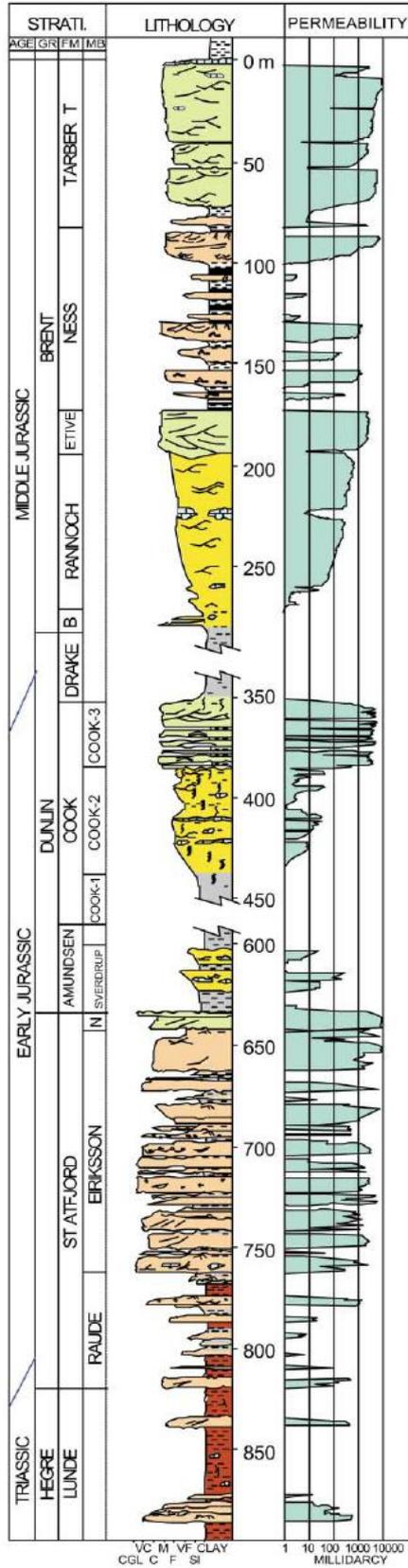
Figure 1.3: Stratigraphic column of Gulfaks oil field

Status of Gulgaks' segments

Segment	Formation	STOOIP (M Sm³)	Recovery Factor Mid 2007		Recovery Factor End 2011	
			M Sm³	%	M Sm³	%
D1 D3 D4	Tarbert	7.9	3.00	38	3.17	40.09
D2 D3		0.49	0.18	37	0.19	38.78
E2 E3		6.7	4.6	69	4.86	72.47
F		43.9	13.8	31	14.57	33.18
G		70.6	58.2	82	61.44	87.02
H		58.2	40.6	70	42.86	73.64
I		9.7	8.0	82	8.44	87.06
D	Ness	0	0	0	0	0
E		0.5	0.1	20	0.11	21.11
F		1.1	0	0	0	0
G		22.9	12.2	53	12.88	56.24
H		27.1	16.5	61	17.42	64.27
I		19.9	11.5	58	12.14	61
G1 G2 G3	Lower Brent	23.5	13.3	57	14.04	59.74
G4 G5 G6 G7		7.7	4.0	52	4.22	54.84
H1		**20.2**	**11.4**	**56**	**12.03**	**59.57**
H2		21.1	11.9	56	12.56	59.53
H3		0.1	0	0	0	0
H4 H5 H6		27.4	16.1	59	17.00	62.03
I1		10.4	4.5	43	4.75	45.68
I2 I3 I4 I5		57.0	33.4	59	35.26	61.85
U1		2.5	0.3	12	0.32	12.67
G	Cook	2.68	0.3	11	0.32	11.82
H1 H2		16.83	5.06	30	5.34	31.74
H3 H4 H5		6.36	0.77	12	0.81	12.78

I1		2.90	0.35	12	0.37	12.74
I2 I5A J1		28.8	9.82	34	10.37	35.99
J2 J3		2.3	0.41	18	0.43	18.82
K		0.2	0	0	0	0
H2	Statfjord	1.3	0.19	15	0.2	15.43
I1		11.00	5.20	47	5.49	49.90
I2A J1 J2		12.30	9.00	73	9.50	77.24
J3		8.2	4.8	59	5.07	61.79
I4B		1.2	0.4	33	0.42	35.19
K1		3.10	0.70	23	0.74	23.84
K2		12.7	5.1	40	5.38	42.39
K3		35.8	21.3	59	22.48	62.81
L		8.8	4.8	55	5.07	57.58
L2	Lunde	3.4	1.00	29	1.06	31.05
K3		1.0	0.01	1	0.01	1.48
SUM		**597.76**	**332.79**	**56**	**351.30**	**58.77**

1.3 H1 segment of Gullfaks oil field
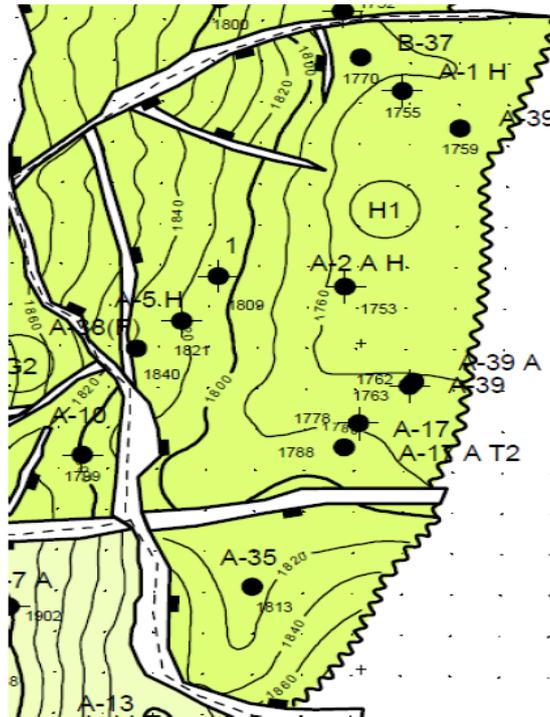
Figure 1.4: H1 segment of the Gullfaks field

Adequacy of H1 segment for EOR pilot testing

The present simulation study for the use of EOR methods is going to focus on the Lower Brent of H1 segment of the Gullfalks field that is illustrated in **Figure 1.4**. Generally, H1 segment for following reasons is considered to be a good field for evaluation of new oil production methods:

- First of all, HI segment is where the production of the Gullfaks field began. That means that it is the most studied area of the whole field with plenty of data available.

- Secondly, H1 segment is isolated meaning that there is no pressure communication or fluid flow to / from the surrounding (vertical or horizontal) formations. By this way the results - impacts of an applied EOR method can be more accurately evaluated. The vertical isolation of H1 segment has been explained in the previous chapter whereas the horizontal isolation is obvious from **Figure 1.4** where the faults that surround and seal HI segment are illustrated.

- Finally, as it can be seen from **Figure 1.3** where the stratigraphic column of Gullfalks field is illustrated, the Lower Brent can be characterised as a reservoir with relatively good properties. The permeability is relatively high and the good lateral continuity enables the use of fluid displacement menthods.

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Properties of H1 segment

From **Table 1.5** it can be seen that H1 segment in the lower Brent had initially Stock Tank Oil Originally In Place 20.2 M Sm^3 from which 12.3 has already been produced (2011 data) resulting in a Recovery Factor of 59.57%. From the above it is clear that the target oil quantities are the immobile part as the mobile fraction of the reservoir's oil has already been produced. In Table 1.5 the summarised reservoir properties of H1 segment are illustrated. [2] [3] [4]

It could be deducted that the reservoir's quality is good and the remaining oil quantities can justify the need for implementation of a EOR method. As it can be seen the oil is undersaturated with the reservoir's pressure to exceed by 100 bar (1450 psi) crude's oil bubble point. The maintenance of the pressure above the bubble point is attributed mainly to the water injection but a contribution of the natural aquifer must also be referred.

Table 1.5: H1 Segment – Reservoir properties

H1 Segment		
Porosity	Etive	33%
	Rannoch	11 – 33%
Permeability	Etive	20 – 5000 mD
	Rannoch	10 – 1000 mD
Recovery Factor (2011)	59.57%	
STOOIP	20.2 M Sm^3	
Already produced (2011)	12.3 M Sm^3	
Reservoir's Temperature	74 ^{0}C	
Reservoir's Pressure	310 bar (4496 psi)	
Bubble point Pressure	210 bar (3046 psi)	
B$_o$	1.2	
True vertical depth mean sea level (TVD MSL)	1850 m	

Properties of H1 segment's crude oil

In **Figure 1.5** the properties of the crude oil produced by the H1 segment of Gullfaks oil field are illustrated. [5] It can be seen that is a light crude oil (39.1 ^{0}API), low viscous, with relatively low sulphur content. Generally the crude oil could be characterised as of high quality.

Statoil

Crude: **GULLFAKS 2014 03**
Reference: **GULLFAKS201403**

Crude Summary Report

General Information		Molecules (% wt on crude)		Whole Crude Properties	
Name:	GULLFAKS 2014 03	methane + ethane	0,07	Density @ 15°C (g/cc)	0,829
Reference:	GULLFAKS201403	propane	0,52	API Gravity	39,1
Traded Crude:	Gullfaks	isobutane	0,33	Total Sulphur (% wt)	0,22
Origin:	Norway	n-butane	1,10	Pour Point (°C)	-9
Sample Date:	16 mars 2014	isopentane	0,90	Viscosity @ 20°C (cSt)	5
Assay Date:	15 august 2014	n-pentane	1,30	Viscosity @ 40°C (cSt)	3
Issue Date:	15 august 2014	cyclopentane	0,17	Nickel (ppm)	1,4
Comments:		C_6 paraffins	2,56	Vanadium (ppm)	1,1
		C_6 naphthenes	1,76	Total Nitrogen (ppm)	682
		benzene	0,40	Total Acid Number (mgKOH/g	0,11
		C_7 paraffins	2,46	Mercaptan Sulphur (ppm)	5
		C_7 naphthenes	2,81	Hydrogen Sulphide (ppm)	0,0
		toluene	1,11	Reid Vapour Pressure (psi)	8,2

Figure 1.5: H1 segment - Crude oil properties

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Production experience from H1 segment

Nowadays the production in H1 segment is supported by water injection in order to preserve the reservoir pressure above the bubble point. As it has already explained the large grain size sandstones that constitute Etive and Rannoch reservoir result in large permeability variations that vary from 10 to 5000 mD. This has as a result the water flow to go through the most permeable layers leaving the low permeability areas unswept. Subsequently, the production is characterised by high values of water cut and the reservoir by high values of residual oil saturation due to the bypassed oil quantities of the unswept zones. The production status in the HI segment is depicted in **Figure 1.6**. It can be seen that the injected water go through the most permeable layers which in the present situation are the upper part of the Rannoch formation and the lower part of the Etive formation. The injection well is located at the left whereas the production well at the right. Ii can also be seen that the reservoir has 12^0 of inclination.

From all the above it could be deducted that in the H1 segment an EOR method which could diverse the water flow to the layers of lower permeability would increase significantly the volumetric sweep efficiency and subsequently the overall oil recovery efficiency.


Figure 1.6: Water preferential path way in the H1 segment

1.4 EOR screening criteria for Gullfaks oil field

Thermal EOR methods

The Gullfaks' crude oil properties which are illustrated in **Figure 1.5** indicate that is clearly a light crude oil. As it has already been mentioned in Chapter 3 Thermal EOR methods, regardless the technology applied, aim to provide thermal energy to a specific part of the reservoir. The increase in the temperature of the reservoir has as a result the decrease in the oil's viscosity and subsequently the change on the crude oil's hydrodynamic properties. From all the above it is clear that the Thermal EOR methods will be ineffective in Gullfaks oil field and cannot be implemented.

Miscible flooding EOR methods

Given the fact that the H1 segment is already waterflooded and that exhibits very high permeability variations any possible miscible flooding method should adopt the WAG technique in order to improve the sweep efficiency. As it has already explained the overall oil recovery efficiency (E) is defined as:

$$E = E_V * E_D$$

Where:

E_V is the volumetric sweep efficiency or macroscopic displacement efficiency.

E_D is the microscopic displacement efficiency.

All the miscible flooding EOR methods target the miscibility condition between the displacing and the displaced fluid in order to achieve the highly effective miscible displacement of the residual oil quantities. That means that the miscible flooding EOR methods target to increase the E_D parameter of the overall oil recovery efficiency.

As it has already been explained, an increase of the microscopic displacement efficiency (E_D) cannot be so effective in the H1 segment of the Gullfaks oil field because due to the large permeability contrasts large reservoir volumes remain unswept. The residual oil saturation of the already swept zones may decrease further more after implementation of a miscible flooding EOR technique but the oil quantities of the unswept zones will not be able to be displaced.

In a few words in the H1 segment the overall oil recovery efficiency (E) will be much more increased by implementation of an EOR method that could affect the macroscopic displacement efficiency E_V. In the case of miscible flooding EOR methods their inadequate nature to increase the volumetric sweep efficiency (E_V) could be mitigated by the fact that the H1 segment has an inclination of 12^0 and gravity segregation could increase at an extent the volumetric sweep efficiency. Another way to for the displacing fluid to reach the unswept zones is the drilling of injection wells in the corresponding areas which in the case of the offshore Gullfaks field constitutes a very expensive procedure. Furthermore the following issues for each method should be mentioned:

Natural gas injection (WAG)

Generally the injection of the produced associated gas it is not recommended when there is an available market to be sold. In the case of Gullfaks field the associated gas is transferred to a treatment plant on the land via pipelines in order to supply the European market.

LPG/Alcohol slug injection

As it has already mentioned in *Chapter 4* when an LPG slug is used to displace the oil then dry gas is injected to displace the LPG slug. Despite of the very high cost of injection gases, the very low volumetric sweep efficiency that result make this technique completely inappropriate for Gullfaks oil field. In the case of the alcohol injection where water is injected to displace the alcohol the volumetric sweep efficiency is improved but this technique has not been proved to be economically viable evn in onshore oil fields.

CO_2 injection (WAG)

Practically it is not possible to supply Gullfaks oil field with the necessary quantities of CO_2 in an economically viable way. Also, in the limited cases where CO_2 injection has been implemented in offshore installations, significant and expensive modifications have been conducted.

N_2 injection (WAG)

Theoretically N_2 injection could be applied to an offshore field. That would require the installation of the appropriate equipment on the platform for the production of the necessary N_2 quantities via the fractional distillation of the liquefied atmospheric air. The H1 segment is deeply enough buried in order to provide the necessary pressure N_2 miscible displacement requires. From all the miscible flooding EOR methods N_2 injection has the most possibilities to be implemented with an economically viable way. It should me mentioned that a significant restricting parameter is the low viscosity of N_2 that results in a very poor sweep efficiency.

Chemical EOR methods

As it has already been mentioned, Gullfaks is a mature oil field where most of the mobile oil quantities have been already produced. That means that the future target oil formations are mostly the immobile oil quantities which are left back in the reservoir either because they have been by passed from the water flow or because they are restrained by capillary forces. As it has already been presented in Chapter 5, Chemical EOR methods aim to reduce the previously mentioned phenomena by decreasing the mobility ratio between the displacing and the displaced fluid or by reducing the interfacial tensions between oil and water quantities.

Concerning the parameters that could decrease the effectiveness of the Chemical EOR methods it should be referred that:

- The reservoir's Temperature is low (74 ^{0}C) and does not affect the stability of the chemicals.

- The formation rock has moderate low clay content [2]

- The formation water has increased salinity around 42 gr/l [2]

- The disposal of the contaminated production water to the sea is able to cause severe environmental problems.

For all the above reasons, concerning Gullfaks oil field, Chemical EOR methods demonstrate the highest potential for commercial viability when compared with the other EOR methods. The parameters that could complicate the implementation of chemical EOR methods are mostly the increased salinity of the formation water and the disposal of the contaminated production waters. In case of real chemical EOR implementation appropriate equipment for water production treatment should be installed. The simulation study will focus only in the Chemical EOR methods.

1.5 References

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[4] NTNU – Enhanced oil recovery with infill drilling a Gullfaks

http://www.ipt.ntnu.no/~kleppe/pub/Gullfaks-Reports-2012/Technical/G3_Technical_Report.pdf

[5] Statoil
http://www.statoil.com/en/OurOperations/TradingProducts/CrudeOil/Crudeoilassays/Pages/GullfaksBlend.aspx

Chapter 2 Reservoir Simulation

2.1 Introduction

Advanced reservoir simulation constitutes the most accurate approach in order to select the appropriate EOR technique which exhibits the best performance when the special features of the under study reservoir are taken into consideration. If the results of the simulation indicate that the implemented EOR technique is technically feasible and financially viable then a pilot project could take place and if it is successful then the EOR technique could be applied to the whole field.

In this simulation study the fluids behaviour of the H1 segment of the Gullfaks oil field is going to be simulated when Chemical EOR methods are implemented. As a reservoir simulation software the ECLIPSE - 100 (2010 version) is going to be used. The optimisation process is going to focus on the maximisation of the incremental oil recovered over water flooding (**technical criterion**) with the less possible mass of chemicals injected (**economical criterion**).

As an evaluation tool of each chemical method's effectiveness the Net Present Value (NPV) is going to be used. Net Present Value can be defined as the difference between the Present Value of cash inflows and the present value of cash outflows. Generally, the same amount of money is worth more if received in the present than in the future. This is because of inflation and the fact that this amount of money could have an economic performance, at least the commercial bank's interest. For a project to be considered economically viable or in other words not economically damaging, Net Present Value should be a positive number. The mathematical definition of Net Present Value is given below:

$$Net\ \Pr esentValue\ = \sum_{t=0}^{N} \frac{B_t - C_t}{(1 + i_R)^t * (1 + f)^t}$$

Where:

t is the time (in the present situation is a year)

B$_t$ is the cash inflow in a year

C$_t$ is the cash outflow in a year

i$_R$ is the annual interest rate

f is the annual inflation

The present simulation study of the H1 segment of the Gullfaks oil field is going to examine the optimisation of the following 4 different chemical flooding processes that are illustrated below. These types of chemical flooding were chosen because they demonstrate the higher possibility for economic viability. At a second step, the performance of the 4 optimum chemical flooding scenarios will be compared in order to identify which suits better for the H1 segment in terms of Net Present Value (NPV).

1. Polymer flooding
2. Polymer - Alkaline flooding
3. Polymer - Surfactant flooding
4. Polymer - Alkaline - Surfactant flooding

2.2 Assumptions

For the economical evaluation of the Chemical EOR project and the estimation of the Net Present Value, several assumptions were made that are presented below:

1. Cost of Chemicals

The cost of the chemicals was estimated taking into consideration the economics of the ASP flooding project that was implemented in the Cambridge field in Crook County, Wyoming, U.S.A. (Chapter 5.7). In these values an increase of 25% was made because Gullfaks oil field is offshore and it is expected the chemicals to be available at higher cost when compared with an onshore oil field, due to lack of accessibility. The costs of the chemicals used in the simulation study are illustrated in the 3rd line (Gullfaks field) of **Table 2.1.**

Table 2.1: Assumed values for the cost of chemicals in Gullfaks field

Location	Units	Cost of chemicals		
		Alkali	Surfactant	Polymer
Cambridge field	($/lb)	0,12	2	1,2
Cambridge field	($/Kg)	0,26	4,41	2,65
Gullfaks field	($/Kg)	0,325	5,51	3,31

*1 lb = 0,4536kg

2. Cost of Equipment

Generally, the implementation of a chemical EOR project requires extra equipment for the storage of the chemicals and the treatment of the water that is injected and produced. For the case of H1 segment of Gullfaks oil field a small tanker will be required to carry the necessary equipment and the storage tanks. It is assumed that the cost of using such a tanker is **50.000 $ /month**.

3. Annual interest rate (i_R)

As an annual interest rate **(i_R)** the London Interbank Offered Rate (Libor) was used. Libor is defined as the interest rate at which banks offer to lend funds to one another in the international interbank market. In other words it reflects how much it costs banks to borrow from each other. The Libor (1 Year) was set equal to **1,689 %** at 1/5/2017.[1]

4. Annual inflation (f)

According to the European Central Bank the annual inflation **(f)** for the OECD area was equal to **0,6%** in 2015. Generally, annual inflations exhibit a relative volatility but for this simulation study it will be assumed as stable. [2]

5. Fiscal regime

Generally, companies which are involved in offshore petroleum extractive activities within the Norwegian geographic areas are subjected to a marginal tax rate of 78% (27% ordinary corporate income tax and 51% resource rent tax) on the net operating profits derived from its extractive activities as it is described in **Table 2.2.** [3]

Table 2.2: Norwegian fiscal regime

	Oil and gas companies (offshore tax regime)	Other companies (onshore tax regime)
Ordinary tax	27%	27%
Special tax	51%	None
Total tax	78%	27%

6. Oil price

The oil price during the simulation process was assumed to be equal with 60$/bbl and stable for the entire period of the simulation: 1DEC 1998 – 1NOV 2008.

2.3 Description of the Reservoir
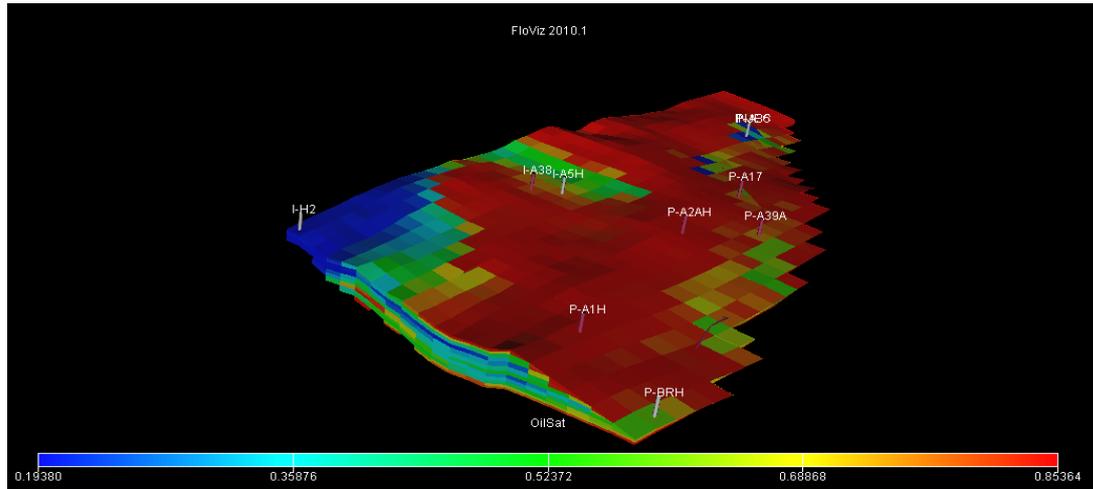
Figure 2.1: H1 Segment of Gullfaks oil field

In **Figure 2.1** the H1 segment of Gullfaks oil field is illustrated. The colours indicate the oil saturation in the different areas of the field. With red colour are represented the areas where oil saturation is around 0,85% which is the initial value before the start of exploitation. With the blue colour are represented the areas where oil saturation is around 0,2% as a result of the primary and secondary production. The oil saturation state that is illustrated in **Figure 2.1** is at 1NOV 1998 means exactly before the start date of the simulation process. The production and injection wells of H1 segment are also illustrated in **Figure 2.1** which are also presented in **Table 2.3** and **Table 2.4**. In the simulation study that follows 3 production wells and 1 injection well are going to be used (those which are shaded in the tables) for reasons that are going to be analysed at the following pages.

Table 2.3: Production wells of H1 segment

Production wells			
Nr	Code name	Type	Status
1	P-A1H	Vertical	Operational
2	P-BRH	Horizontal	Not - Operational
3	P-A2AH	Vertical	Operational
4	P-A39A	Horizontal	Operational
5	P-A17	Vertical	Operational
6	P-A35	Horizontal	Operational

Table 2.4: Injection wells of H1 segment

Injection wells			
Nr	Code name	Type	Status
1	I A38	Horizontal	Operational
2	I A5H	Vertical	Operational
3	I H2	Vertical	Operational
4	INJEC	Vertical	Not - Operational

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2.4 History matching

History matching is a procedure that aims to the improvement in the accuracy of a given reservoir's geological model by using the most reliable field production data. The initial geological model of a reservoir involves errors and approximations because the actual geology of the reservoir cannot be described with absolute accuracy. Therefore the productivity forecasts that are based on the initial geological model include a large degree of uncertainties. In order to forecast the future reservoir performance as accurately as possible and subsequently to optimise the reservoir management, the productivity forecasts are continuously updated by the dynamic production data.

In **Figure 2.2** the cumulative oil productions of all the H1 segment's production wells before history matching, are illustrated. It is obvious there is a deviation between the historical production data that are available after a period of production and the values given by the available geological model. As it can be seen from the diagram, the management of the field has decided to close three of the production wells (P-A1H, P-A2AH and P-A17) because their low production did not allow their viable operation.
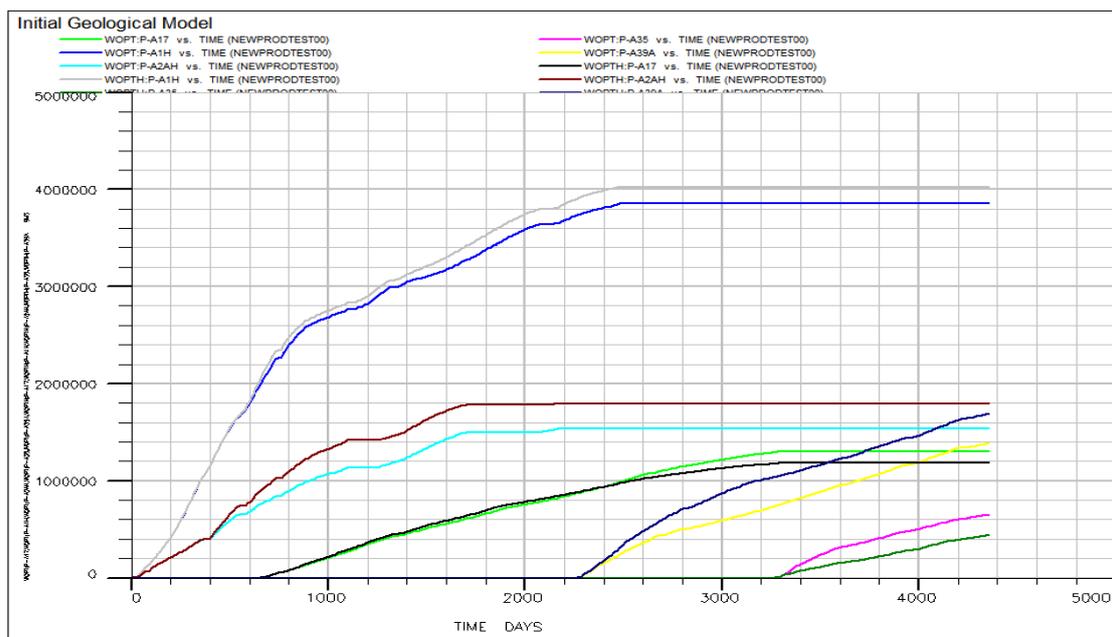
Figure 2.2: Well's cumulative oil production curves of H1 segment before history matching

During History matching process the initial geological model is adjusted so as the out coming predictions to approach as much as possible the real production data. In **Figure 2.3** the well's cumulative oil production curves after history matching are illustrated. The adjustment of the geological model to the real production data based on the adjustment of the transmissibility on certain grid blocks of the reservoir. Generally, transmissibility depends only on grid block geometry and permeability and it is a measure of how easy a medium flow or transmitted. As it can be seen the divergence between the two curves has been decreased significantly which means that the errors in the flux calculation have been minimised and subsequently, the reliability of the geological model has been increased.

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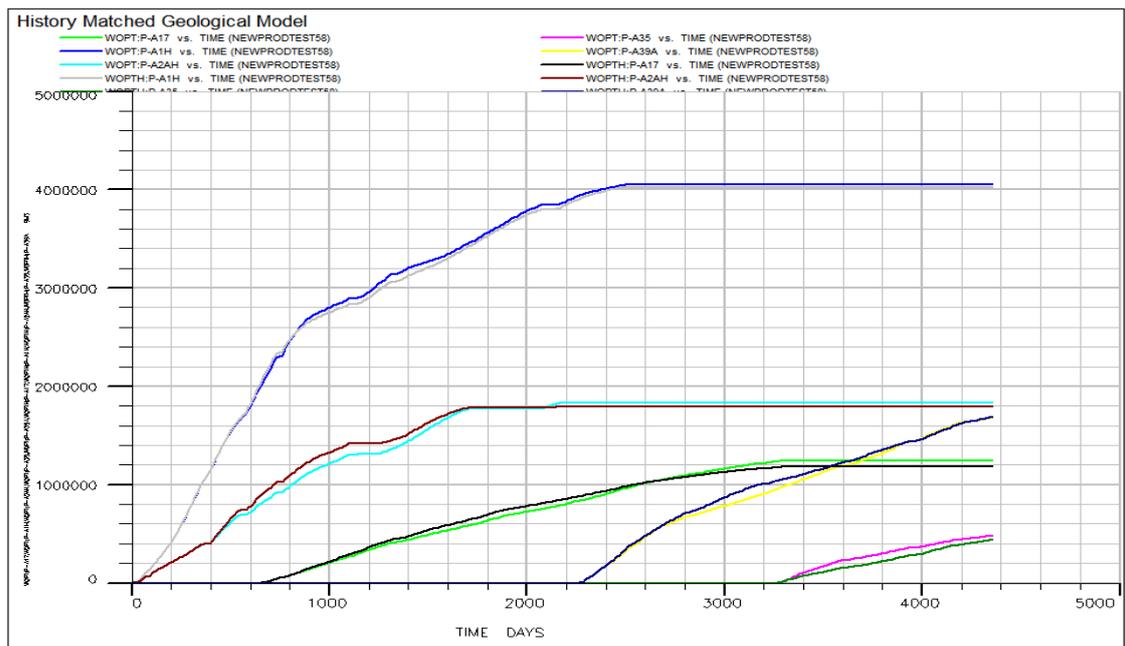
Figure 1.3: Well's cumulative oil production curves of H1 segment after history matching

2.5 Base case formation

According to the historical data of H1 Segment, the secondary oil production of the field was based on two Injectors as illustrated in **Table 2.5.**

Table 2.5: Operational Injectors of H1 Segment (Historical Data)

Injector	Start	End
I – A5H	1 APR 1987	1 MAY 1993
I – A38	1 NOV 1992	1 NOV 1998

The selection of the appropriate injector to use for chemical flooding depends on the performance that each injector exhibits. The purpose is to maximise the profit (incremental oil production) for the same amount of chemicals used. In order to evaluate the two injectors, chemical floodings were simulated for a period of 10 years, the results of which are presented in **Table 2.6**. The two injectors are firstly operating at the same water rate (700 m^3/day) without chemical injection and the cumulative field oil production is recorded. In a second step the same quantity of polymers is injected – same polymer concentration (0,5 kg /m^3) and same slug size (constant injection of the solution for 6 months).

As it can be seen from **Table 2.7** the incremental oil production is higher when Injector I – A38 is used. The difference in the injectors' performance could be explained by the geological heterogeneities of H1 segment that make the producer wells more accessible to the Injector I – A38. It must also be referred that H1 segment cannot be 100% sealed and some injected water may be driven to the surrounding formations, decreasing by this way the effectiveness of an injector.

Table 2.6: Simulation of the two Injectors for evaluation of their performance

Injector	Start	End	Water Rate (m^3/day)	Polymer Concentration (kg/ m^3)	Slug Size (months of injection)	Field oil production total (m^3)
I – A5H	1 DEC 1998	1 NOV 2008	700	0	0	9.701.430
I – A5H	1 DEC 1998	1 NOV 2008	700	0,5	6	9.709.081
I – A38	1 DEC 1998	1 NOV 2008	700	0	0	9.615.027
I – A38	1 DEC 1998	1 NOV 2008	700	0,5	6	9.625.278

Table 2.7: Selection of the appropriate injector for chemical injection

Injector	Incremental oil production total (m3)
I – A5H	7.651
I – A38	10.251

From the above it is clear that Injector I – A38 should be used for chemical flooding. The Base Case scenario where the simulation study that follows is going to rely on, is actually the water flooding via Injector I – A38. In **Figure 2.4** the cumulative field oil production is illustrated when the field is waterflooded from Injector I – A38 at constant water rate 700 m³/day. It is obvious that the rate of oil production is decreasing especially after 1 DEC 1998. In **Table 2.8** the detailed data of **Figure 2.4** are illustrated. The performances of the chemical injection methods will be evaluated by the annual incremental oil productions achieved when compared with the annual field oil production of the waterflooding scenario (**Table 2.8)** for the same period of simulation: 1DEC 1998 – 1NOV 2008.
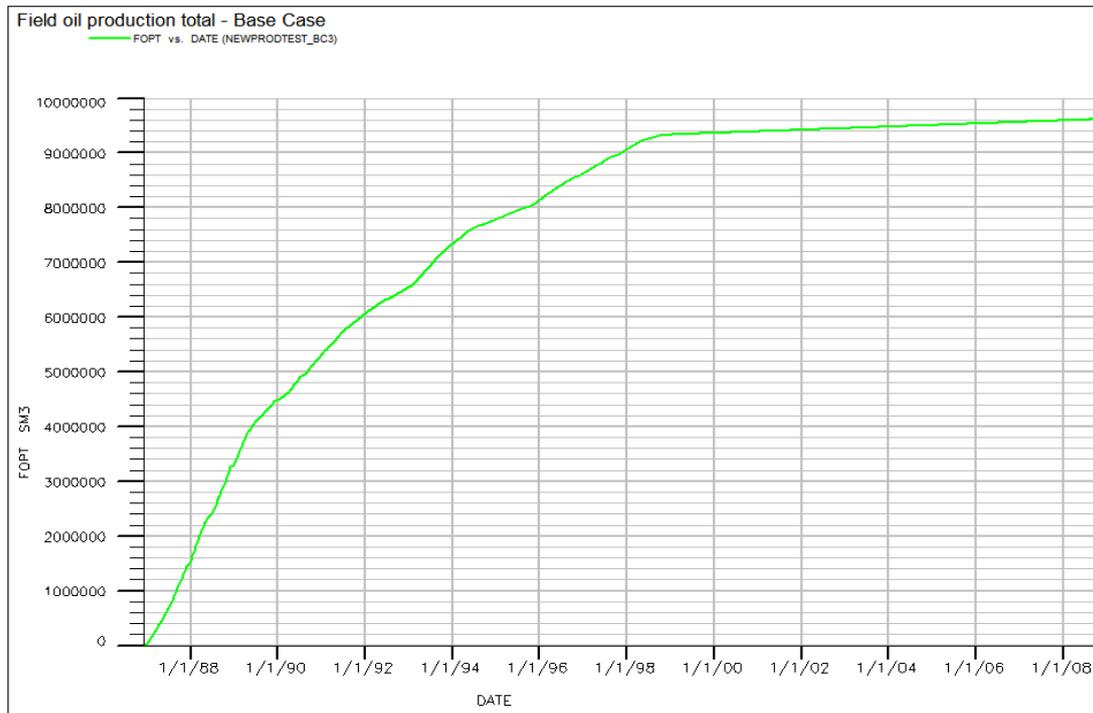
Figure 2.4: Field oil production total - Base Case

Table 2.8: Field Cumulative and Annual Oil Production

	Year	Field Oil Production (m³)	Annual Field Oil Production (m³)
	1 DEC 1986 - 31 NOV 1998	9329671	
1	1 DEC 1998 - 31 NOV 1999	9360182	30511
2	1 DEC 1999 – 31 NOV 2000	9388386	28204
3	1 DEC 2000 – 31 NOV 2001	9416543	28157
4	1 DEC 2001 – 31 NOV 2002	9446460	29917

5	1 DEC 2002 – 31 NOV 2003	9475237	28777
6	1 DEC 2003 – 31 NOV 2004	9503802	28565
7	1 DEC 2004 – 31 NOV 2005	9532239	28437
8	1 DEC 2005 – 31 NOV 2006	9561848	29609
9	1 DEC 2006 – 31 NOV 2007	9589550	27702
10	1 DEC 2007 – 1 NOV 2008	9615027	25477

In **Figure 2.5** the field pressure is illustrated. It can be seen that during the simulation period (1DEC 1998 – 1NOV 2008) the field pressure id decreasing at a constant rete. This is because the flow rate of Injector I – A38 has decreased on purpose. The chemicals consumption is decreased when the water flow rate is a lowered and as a result the economics of the EOR project are improved. The Bubble Point is estimated to be around 210 bar, so there is not a chance for the formation of the gas phase in the flow.
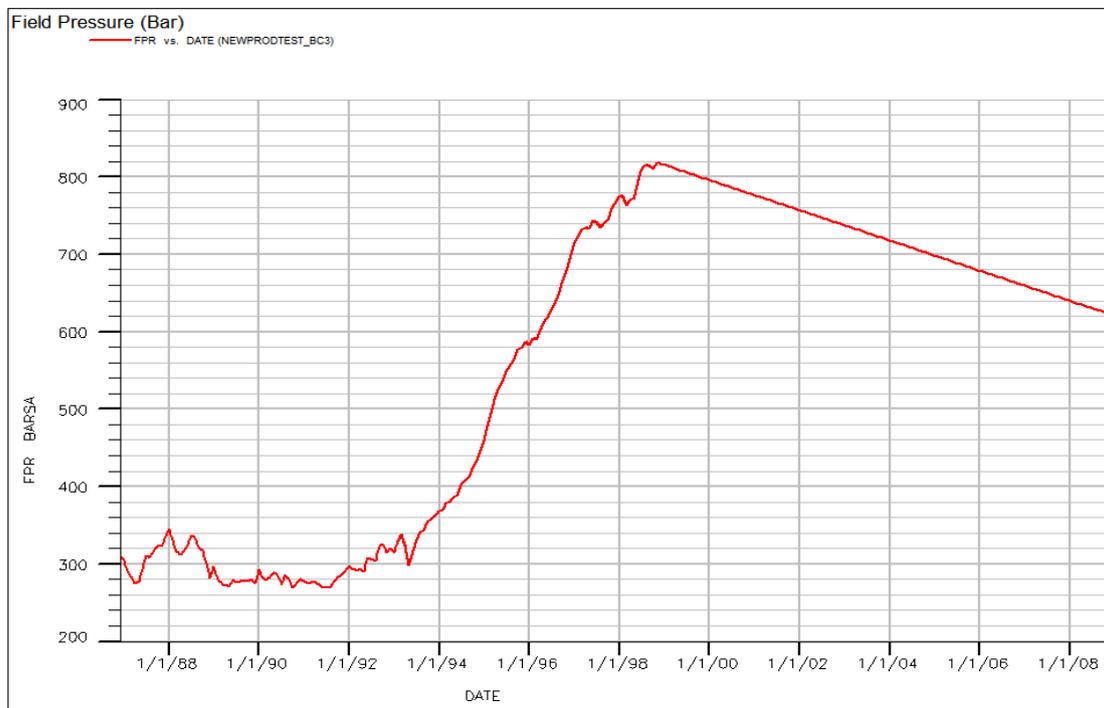
Figure 2.5: Field Pressure - Base Case

In **Figure 2.6** the field oil saturation is illustrated. It is obvious that after a point conventional waterfloooding cannot decrease efficiently the oil saturation of the field. In **Figure 2.7** the field water cut is illustrated. It must be referred that two of the production wells were excluded from the simulation process of the period (1DEC 1998 – 1NOV 2008). More specifically, the well P-A39A was unstable and subsequently inappropriate for outcome of useful conclusions. The instability the well P-A39A imports is obvious in **Figure 2.7.** Concerning the well P-A2AH, it had already reached water cut equal to unity and could not be considered as a productive well so it was decided to close. For the present simulation study 3 production wells will remain operational: P-A17, P-A1H and P-A35 along with one injector:I-A38
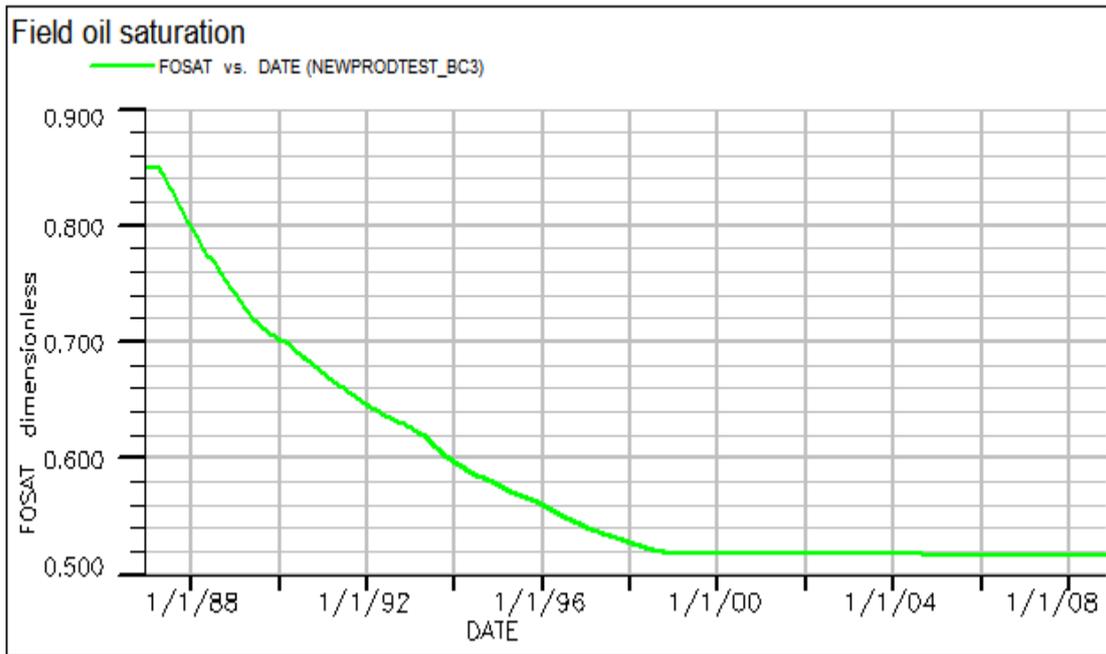
Figure 2.6: Field oil saturation – Base Case
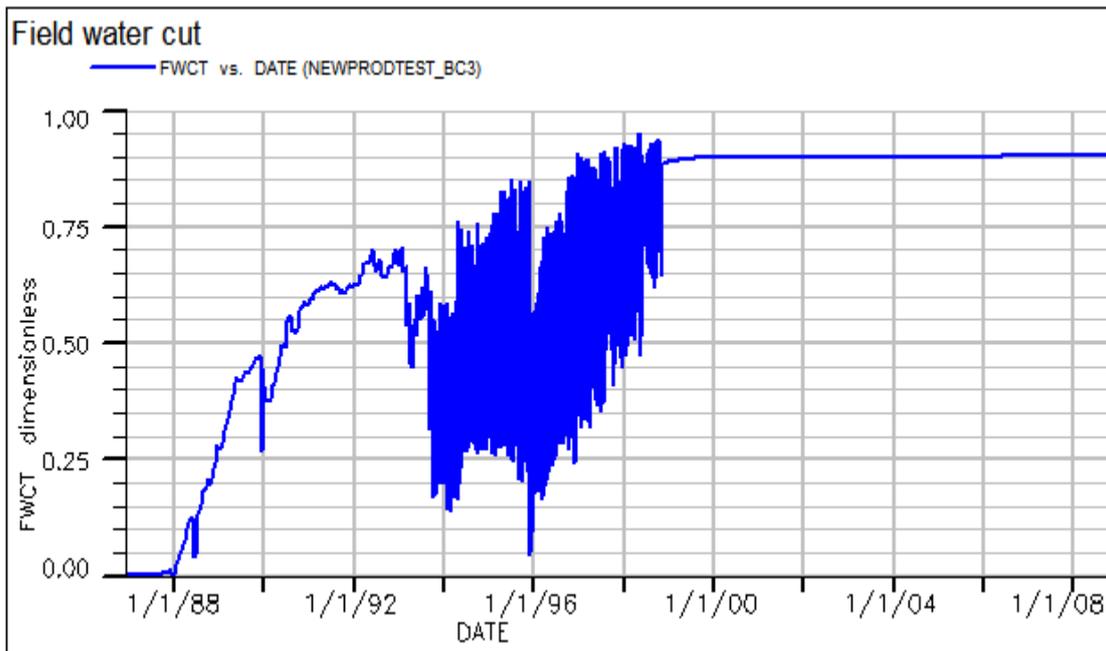
Figure 2.7: Field water cut

2.6 Optimization of Polymer flooding

As it has already been mentioned (Chapter 5.2*)* Polymer flooding involves the injection of a slug – solution of polymers that normally account for 30 - 50% of the target reservoir's pore volume which is then followed by water / brine injection to drive the oil bank to the surface. Field implementations have shown that polymer flooding has the potential of an incremental recovery factor that could range between 5 – 30% of the oil originally in place. In **Figure 2.8** the optimization process of polymer flooding that was used in the present simulation study is illustrated.
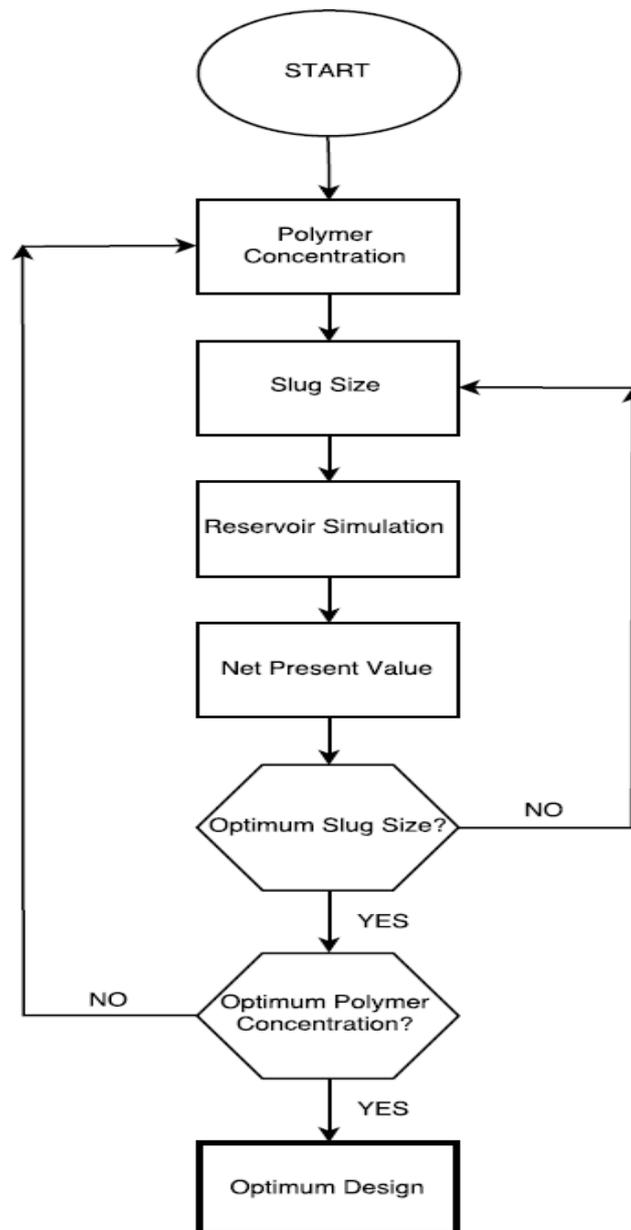
Figure 2.8: Optimisation process of Polymer flooding

In **Table 2.9** the procedure for the determination of the optimum polymer flooding is presented. It is obvious that by increasing the Polymer concentration or the volume of the injected slug the incremental oil recovery is increasing. For this reason Net Present Value is used to determine the best polymer flooding design. **Table 2.10** illustrates the procedure for the configuration of the Net Present Value (optimum polymer flooding scenario).

Table 1.9: Procedure of Polymer flood optimisation

Runs	Slug Size (months of injection)	Polymer Concentration (kg/m^3)	Incremental oil recovery (bbl)	Net Present Value ($)
Determination of optimum polymer slug size				
1	6	0,5	64.476	271.997
2	9	0,5	90.485	332.647
3	12	0,5	114.059	357.249
4	24	0,5	191.958	276.417
5	36	0,5	255.982	44.866
Determination of optimum polymer concentration				
6	12	0,8	165.453	711.563
7	12	1,5	262.391	1.244.310
8	12	3	399.654	1.560.235
9	12	4	476.622	1.619.892
10	12	5	550.364	1.638.872
11	12	6	619.337	1.598.841
12	12	4,5	515.147	1.650.173

Table 2.10: Configuration of Net Present Value for optimum Polymer flooding

Simulation Year	Annual incremental oil production (bbl)	Annual Inflow ($)	Annual Inflow after tax ($)	Annual Outflow ($)	Present Value	Net Present Value
						1.650.173
1	-1.144	-68.684	-15.110	4.356.375	-4.273.201	
2	11.447	686.846	151.106		144.391	
3	33.927	2.035.630	447.838		418.540	
4	57.671	3.460.270	761.259		695.214	
5	93.541	5.612.514	1.234.753		1.102.458	
6	112.335	6.740.149	1.482.832		1.293.920	
7	81.735	4.904.157	1.078.914		920.575	
8	30.908	1.854.484	407.986		340.272	
9	48.381	2.902.868	638.631		520.566	
10	46.343	2.780.594	611.730		487.434	

2.7 Optimization of Surfactant - Polymer flooding

As it has already been mentioned in Chapter 5.6 when the surfactants' concentration in the injected solvent is increasing, the water /oil interface is covered by more surfactants and as a result the interfacial tension is decreasing inversely. If we increase the surfactant concentration beyond the CMC value (Critical Micelle Concentration) then the surface tension (or surface energy) is not decreasing furthermore and micelles are formed.

Based on the effect that surfactants' concentration have in the oil recovery mechanism the first step of Surfactant – Polymer flooding optimisation was to identify the Critical Micelle Concentration. As it can be seen from **Table 2.11** (Runs 1-6) when surfactants are added in the optimum polymer flooding scenario, the maximum oil recovery occurs at a surfactants' concentration equal with 0,25 kg/m^3 (Run 5). The criterion for the selection of the optimum surfactants' concentration should not be the Net Present Value but the incremental oil recovery when compared with the polymer flooding. At this concentration the added surfactants demonstrate the maximum performance in the oil recovery.

At a second step, given that surfactants are injected with the concentration which results in the maximum possible incremental oil recovery, the surfactants' slug size was investigated (Runs 7-12). As it can be seen from **Table 2.11** when the injected surfactant slug size is decreased, then the economics (NPV) of the implementation are improved because less quantities of the expensive surfactants are used. However, the decrease in the incremental oil production seems not to be proportional with the decrease of the injected surfactant slug size. For the determination of the optimum surfactant slug size the procedure that is illustrated in **Table 2.12** has been followed. As base case the performance of the optimum polymer flooding scenario was used - Incremental oil recovery (bbl) & Net Present Value ($). The performances of the different surfactant slug size flooding scenarios were compared. Two parameters were formed: the increase upon the incremental oil recovery of the polymer flooding and the corresponding decrease in the Net Present Value of the optimum polymer flooding scenario. Then by dividing these two parameters a Ratio ($/bbl) is formed which describes the impact of each incremental barrel of oil that is produced upon the decrease in the Net Present Value (when polymer flooding is used as a base case). It can be seen that the cost per produced barrel is less in the case of surfactant slug size equal with 12 months.

Finally the optimum surfactant slug scheme was investigated. Given that is not beneficial to decrease the slug size beneath 12 months of injection it was tried to increase the polymer slug size (Runs 13-14). It was found out, as in the previous step, that surfactant slug has better results in incremental oil production when it is equal with the polymer slug size, means 12 months for the specific circumstances. Furthermore, the extension of polymer flooding beyond the 12 months results in a decreased Net Present Value. Consequently, as optimum surfactants' slug size was chosen that of 12 months means to be injected simultaneously at concentration of 0,25 kg/m^3 with the optimum polymer flooding. **In Figure 2.9** the optimisation process of Surfactant – Polymer flooding is illustrated.
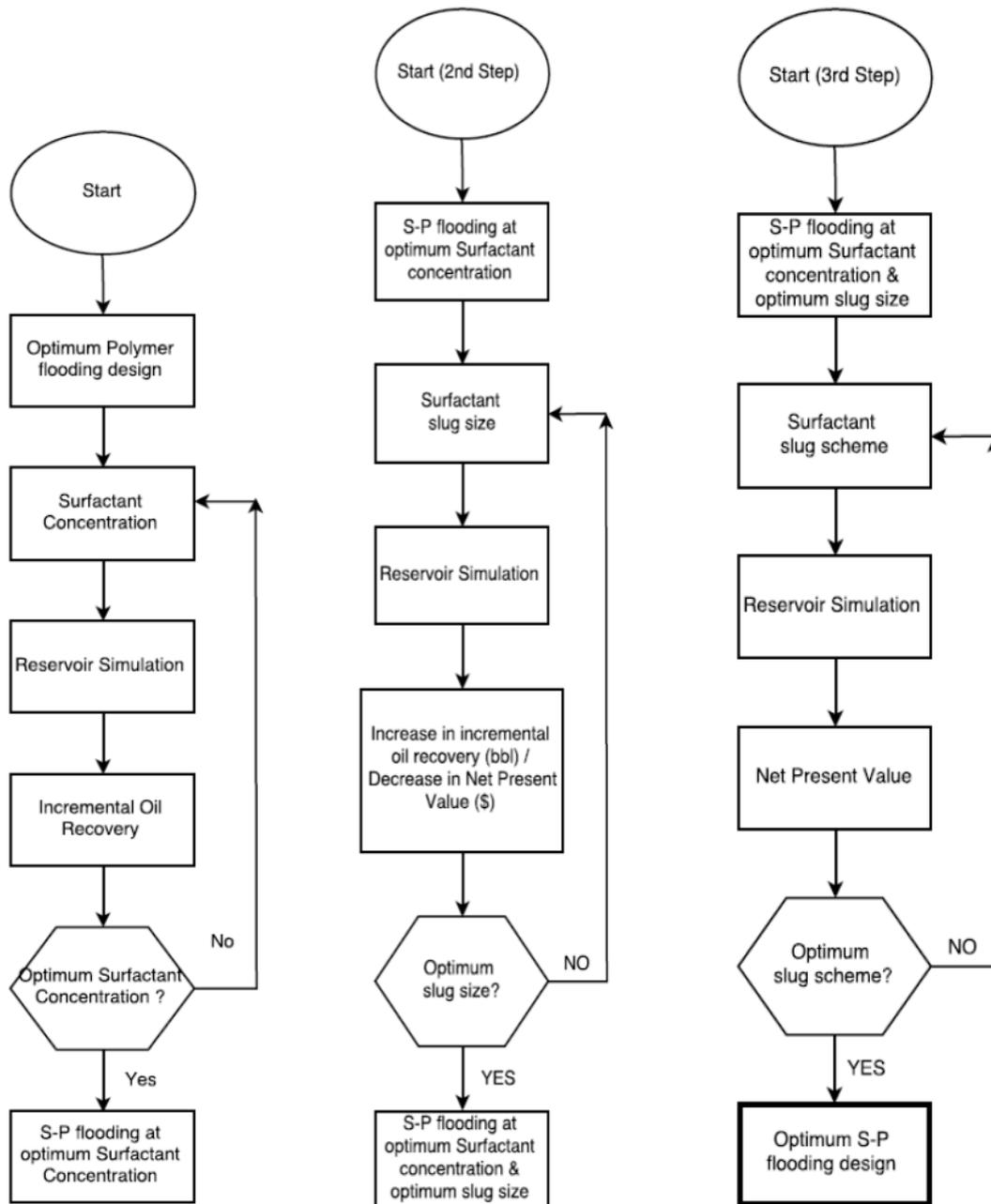
Figure 2.9: Optimisation process of Surfactant - Polymer flooding

	Polymer slug		Surfactant slug		Results	
Runs	Slug Size (months of injection)	Polymer Conc. (kg/m^3)	Slug Size (months of injection)	Surfactant Conc. (kg/m3)	Incremental oil recovery (bbl)	Net Present Value ($)
			Determination of optimum surfactant concentration			
0	12	4,5	0	0	515.147	1.650.173
1	12	4,5	12	2	512.700	-1.097.477
2	12	4,5	12	1	514.914	289.449
3	12	4,5	12	0,5	515.512	973.319
4	12	4,5	12	0,3	515.637	1.246.220
5	12	4,5	12	0,25	515.851	1.317.092
6	12	4,5	12	0,2	515.600	1.382.024
			Determination of optimum surfactant slug size			
	12	4,5	12	0,25	515.851	1.317.092
7	12	4,5	11	0,25	515.600	1.342.606
8	12	4,5	10	0,25	514.631	1.359.643
9	12	4,5	9	0,25	515.323	1.395.975
10	12	4,5	8	0,25	515.398	1.425.124
11	12	4,5	7	0,25	515.222	1.450.694
12	12	4,5	6	0,25	514.977	1.476.530
			Determination of optimum surfactant slug scheme			
13	15	4,5	15	0,25	593.354	1.061.881
14	15	4,5	12	0,25	592.876	1.140.138
			Optimum Surfactant – Polymer flooding design			
	12	4,5	12	0,25	515.851	1.317.092

Table 2.12: Procedure for the determination of the optimum surfactant slug size

Slug size (months of injection)	Incremental oil recovery (bbl)	Increase in Incremental oil recovery (bbl)	Net Present Value ($)	Decrease in Net Present Value ($)	Ratio ($/bbl)
0	515.147		1.650.173		
12	515.851	704	1.317.092	333.081	473
11	515.600	453	1.342.606	307.567	678
10	514.631	-	1.359.643	-	-
9	515.323	176	1.395.975	254.198	1.444
8	515.398	251	1.425.124	225.049	896
7	515.222	75	1.450.694	199.479	2.659
6	514.977	-	1.476.530	-	-

Table 2.13: Configuration of Net Present Value for optimum Surfactant - Polymer flooding

Simulation Year	Annual incremental oil production (bbl)	Annual Inflow ($)	Annual Inflow after tax ($)	Annual Outflow ($)	Present Value ($)	Net Present Value ($)
						1.317.092
1	-1138	-68.307	-15.027	4.703.662	-4.612.600	
2	11.441	686.468	151.023	0	144.312	
3	33.990	2.039.404	448.669	0	419.316	
4	57.759	3.465.554	762.421	0	696.275	
5	93.359	5.601.570	1.232.345	0	1.100.308	
6	112.606	6.756.377	1.486.403	0	1.297.035	
7	75.653	4.539.222	998.629	0	852.072	
8	37.499	2.249.987	494.997	0	412.841	
9	48.343	2.900.604	638.132	0	520.160	
10	46.336	2.780.217	611.647	0	487.368	

2.8 Optimization of Alkaline - Polymer flooding

As it has already been mentioned in Chapter 5.4 Alkaline – Polymer flooding involves the injection of an alkali slug at a pH value that ranges between 10 and 12 always in conjunction with polymer flooding for mobility control reasons. The alkali solution reacts with the organic acids of the reservoir's crude oil (naphthenic acids) to form surfactants in situ which in turn, have the ability to improve significantly the displacement efficiency of the residual oil. The alkali slug, can also decrease the relevant permeability of the already swept zones and divert the waterflood that follows towards the unswept zones. This technique is more effective in highly viscous oils with high mobility ratios or in highly heterogeneous reservoirs.

It must be mentioned that the performance of Alkaline – Polymer flooding in the specific case (H1 segment) is going to be restricted at an extent by the following parameters:

- The reservoir's crude oil demonstrates relatively low acidity (0,11 mg KOH/gr) as it has been referred in Chapter 2.1. The decreased concentration of the crude oil in naphthenic acids will result in decreased in – situ production of surfactants.

- The horizontal injection well I A38 is not at close distance with the producers. The alkali concentration of the A-P flooding is decreasing as it moves through the reservoir rock because of reaction that occur with the residual oil, the formation water and the reservoir rocks.

- The reservoir's crude oil is light (39.1º API). As it has been mentioned in Chapter 5.4 the interfacial tension at the oil – water surface decreases at higher rates as the oil becomes heavier.

The procedure for the optimisation process of the Alkaline – Polymer flooding is illustrated in **Figure 2.10** and the results of the simulation Runs in **Table 2.14.** As it can be seen the best oil recovery performance of the A-P flooding occurs at Alkali concentration equal with 0,5 kg/m^3. Another point to be made is that the optimum Alkali slug is only 6 months. A possible explanation it could be the low acid number of the reservoir's crude oil. It is very likely that after 6 months of Alkali slug injection, the available naphthenic acids are depleted.

Finally, the Alkali slug scheme was investigated. As it was expected, when the alkali slug is injected continuously then the method has the best performance. Due to the unfavourable mobility ratio that Alkali slugs exhibit it is required to inject significant volumes of polymer solution as a drive slug.
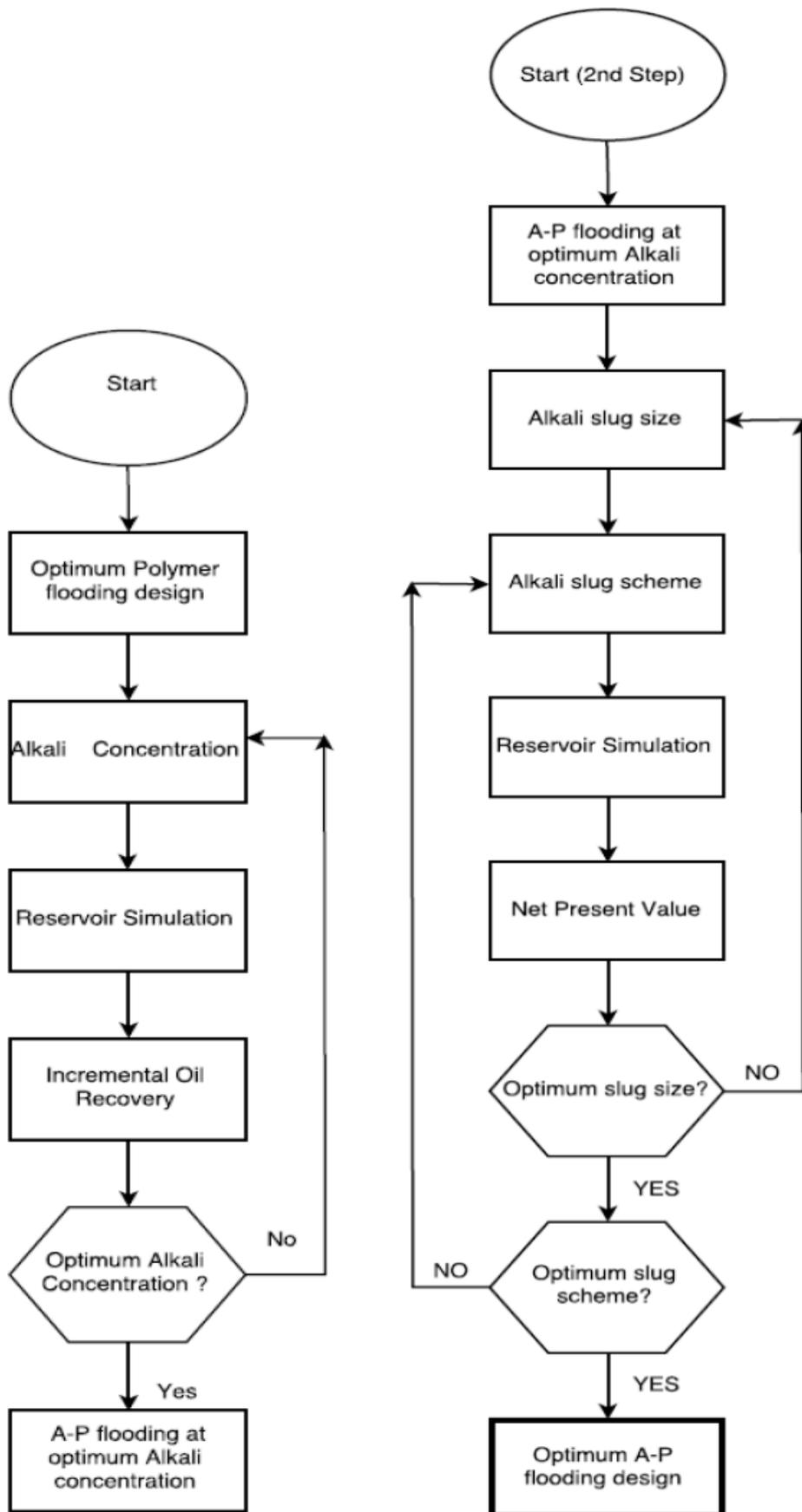
Figure 2.10: Optimisation process of Alkaline – Polymer flooding

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Table 2.14: Procedure of Alkaline - Polymer flooding optimisation

Runs	Polymer slug		Alkaline slug		Results	
	Slug Size (months of injection)	Polymer Conc. (kg/m^3)	Slug Size (months of injection)	Alkali Conc. (kg/m3)	Incremental oil recovery (bbl)	Net Present Value ($)
Determination of optimum alkali concentration for polymer concentration = 4,5 kg/m^3						
0	12	4,5	0	0	515.147	1.650.173
1	12	4,5	12	1	515.304	1.570.266
2	12	4,5	12	2	515.046	1.486.892
3	12	4,5	12	4	515.140	1.328.392
4	12	4,5	12	0,5	515.335	1.610.782
5	12	4,5	12	0,3	515.272	1.625.984
6	12	4,5	12	0,8	515.317	1.586.636
Determination of optimum alkali slug size						
	12	4,5	12	0,5	515.335	1.610.782
7	12	4,5	11	0,5	514.694	1.606.524
8	12	4,5	10	0,5	514.920	1.612.310
9	12	4,5	9	0,5	515.669	1.624.223
10	12	4,5	8	0,5	515.279	1.623.403
11	12	4,5	7	0,5	515.574	1.629.370
12	12	4,5	6	0,5	515.807	1.635.903
13	12	4,5	5	0,5	514.662	1.625.598
14	12	4,5	4	0,5	514.989	1.633.301
Determination of optimum alkali slug scheme						
	12	4,5	6months *1	0,5	515.807	1.635.903
15	12	4,5	1month *6	0,5	514.750	1.622.472
16	12	4,5	2months *3	0,5	514.694	1.621.537
17	12	4,5	3months *2	0,5	514.530	1.619.715
Optimum Alkaline – Polymer flooding design						
	12	4,5	6months *1	0,5	515.807	1.635.903

Table 2.15: Configuration of Net Present Value for optimum Alkaline - Polymer flooding

Simulation Year	Annual incremental oil production (bbl)	Annual Inflow ($)	Annual Inflow after tax ($)	Annual Outflow ($)	Present Value ($)	Net Present Value ($)
						1.635.903
1	-1.151	-69.062	-15.193	4.376.850	-4.293.297	
2	11.258	675.524	148.615		142.011	
3	34.027	2.041.669	449.167		419.782	
4	57.778	3.466.686	762.670		696.503	
5	93.460	5.607.608	1.233.673		1.101.494	
6	112.675	6.760.528	1.487.316		1.297.832	
7	75.615	4.536.958	998.130		851.647	
8	37.430	2.245.835	494.083		412.079	
9	48.299	2.897.962	637.551		519.686	
10	46.412	2.784.746	612.644		488.162	

2.9 Optimization of Alkaline - Surfactant - Polymer flooding

As it has already been mentioned in Chapter 5.7 ASP flooding aims to the synergic effect of the different displacement mechanisms of Alkalis, Surfactants and Polymers which allow achieving higher displacement efficiencies and subsequently higher recovery factors when compared with the previously mentioned flooding schemes.

ASP flooding exhibits very high sensitivity to the well – spacing. Generally it demonstrates very high displacement efficiency in a radius that could extend around 50 m from the injection well. Beyond this distance it is very likely that the integrity of the chemical slug will be disrupted and the displacement efficiency will be decreased, especially in reservoirs with high degree of heterogeneities.

The procedure for the optimisation process of the ASP flooding is illustrated in **Figure 2.11** and the results of the simulation Runs in **Table 2.16.** In the first three lines of **Table 2.16** the optimum Polymer, A-P and S-P flooding designs of the previous steps are illustrated for comparison reasons. In Run 1 the optimum flooding designs were combined together to form a first edition of an ASP flooding based on the previous simulations.

As it has already been mentioned, in Chapter 5.7 by adding alkalis, the loss due to adsorption of the most expensive surfactant component is decreased significantly. For this reason Run 2 has been conducted to investigate the possibility of the alkali slug extension from 6 months to 12 months so as to take advantage of the synergic effect the maximum possible. It is obvious that the alkali slug cannot extent more than 6 months probably due to lack of naphthenic acids.

At a next step given that the alkali slug will be injected for 6 months several alkali – surfactant concentrations scenario were investigated always with the purpose to decrease the quantity of surfactants injected and to improve the NPV. The procedure for the evaluation of the different scenario is illustrated in **Table 2.17.** As base case the performance of the optimum polymer flooding scenario was used - Incremental oil recovery (bbl) & Net Present Value ($). It can be seen that he best scenario is Run 5 which involves injecting Alklis at a reduced concentration ($0,25$ kg/m^3) for 6 months in conjunction with surfactant injection at a reduced concentration ($0,2$ kg/m^3) the first 6 months and for the 6 months that follow the standard concentration of ($0,25$ kg/m^3).

Finally the Surfactant slug size was investigated. It was found out that the highest incremental oil recovery with the highest NPV value, occurs when injecting surfactants for 6 months after the alkali injection (Run 10). The cconfiguration of the Net Present Value for the optimum ASP flooding is illustrated in **Table 2.18.**
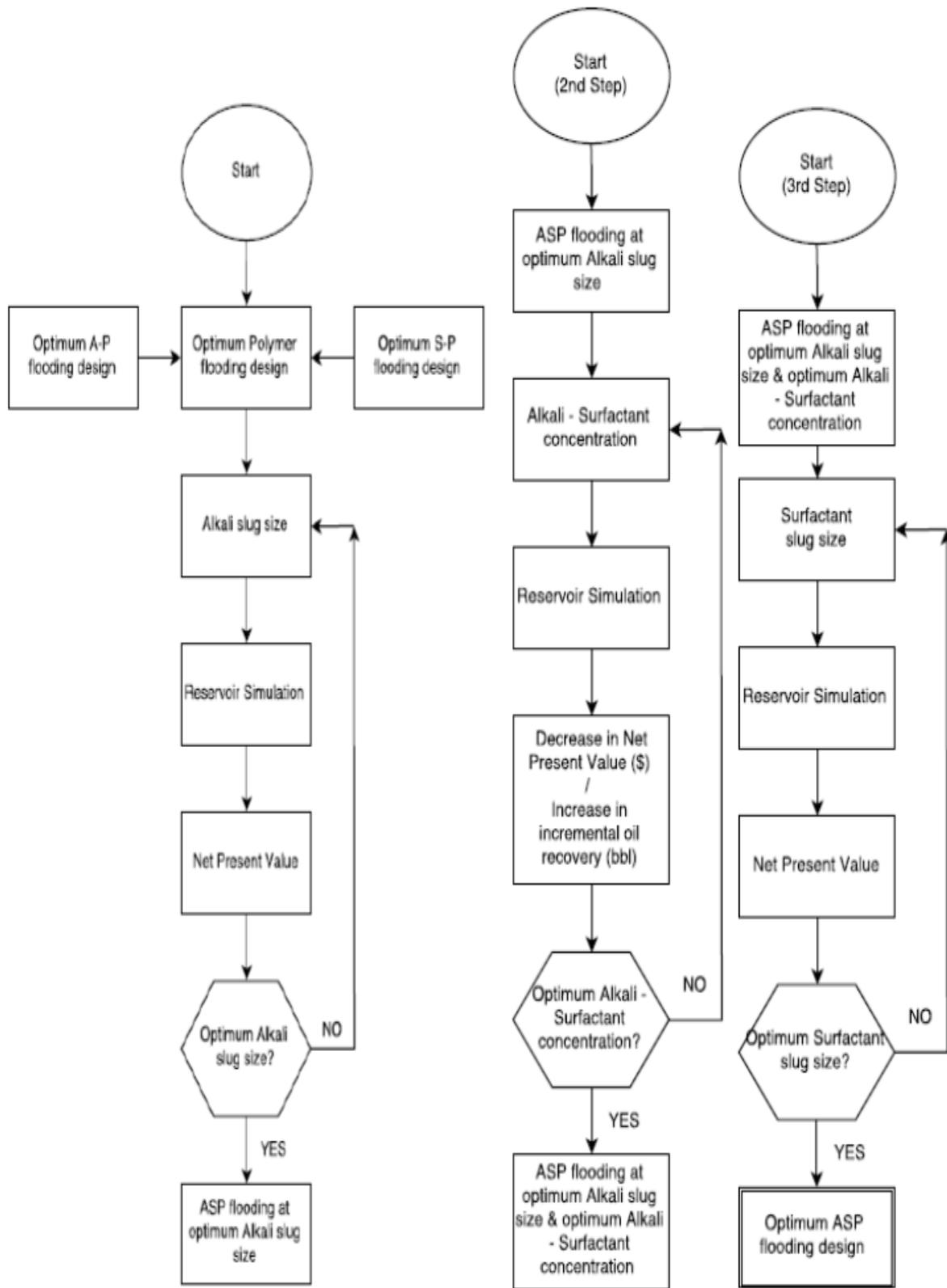
Figure 2.11: Optimisation process of Alkaline - Surfactant - Polymer flooding

Table 2.16: Procedure of Alkaline - Surfactant - Polymer optimisation

Runs	Polymer slug		Alkaline slug		Surfactant slug		Results	
	Slug Size (months of injection)	Polymer Conc. (kg/m^3)	Slug Size (months of injection)	Alkali Conc. (kg/m3)	Slug Size (months of injection)	Surfactant Conc. (kg/m3)	Incremental oil recovery (bbl)	Net Present Value ($)
P	12	4,5					515.147	1.650.173
S-P	12	4,5			12	0,25	515.851	1.317.092
A-P	12	4,5	6months *1	0,5			515.807	1.635.903
Determination of optimum Alkaline slug size								
1	12	4,5	6	0,5	12	0,25	515.713	1.295.771
2	12	4,5	12	0,5	12	0,25	515.373	1.271.410
Determination of optimum Alkali / Surfactant concentration								
3	12	4,5	6	0,5	6 & 6	0,2 & 0,25	515.505	1.326.418
4	12	4,5	6	0,7	6 & 6	0,2 & 0,25	515.203	1.315.396
5	12	4,5	6	0,25	6 & 6	0,2 & 0,25	515.669	1.338.996
6	12	4,5	6	0,15	6 & 6	0,2 & 0,25	515.442	1.339.596
7	12	4,5	6	0,5	6 & 6	0,15 & 0,25	515.386	1.359.037
8	12	4,5	6	0,25	6 & 6	0,15 & 0,25	515.335	1.368.859
Determination of optimum Surfactant slug size								
9	12	4,5	3 & 3	0,5 & 0,25	3 & 6	0,2 & 0,25	515.291	1.396.785
10	12	4,5	6	0,5	0 & 6	0,25	515.908	1.467.180
Optimum Alkaline - Surfactant - Polymer flooding design								
	12	4,5	6	0,5	6	0,25	515.908	1.467.180

Table 2.17: Procedure for the determination of the optimum Alkali - Surfactant concentration

Runs	Incremental oil recovery (bbl)	Increase in Incremental oil recovery (bbl)	Net Present Value ($)	Decrease in Net Present Value ($)	Ratio ($/bbl)
0	515.147		1.650.173		
1	515.713	566	1.295.771	354.402	626
3	515.505	358	1.326.418	323.755	904
4	515.203	56	1.315.396	334.777	5.978
5	515.669	522	1.338.996	311.177	596
6	515.442	295	1.339.596	310.577	1.052
7	515.386	239	1.359.037	291.136	1.218
8	515.335	188	1.368.859	281.314	1.496

Table 2.18: Configuration of Net Present Value for optimum ASP flooding

Simulation Year	Annual incremental oil production (bbl)	Annual Inflow ($)	Annual Inflow after tax ($)	Annual Outflow ($)	Present Value ($)	Net Present Value ($)
						1.467.180
1	-1.169	-70.194	-15.442	4.550.493	-4.463.281	
2	11.321	679.298	149.445		142.805	
3	34.008	2.040.536	448.918		419.549	
4	57.601	3.456.119	760.346		694.380	
5	93.453	5.607.230	1.233.590		1.101.420	
6	112.826	6.769.585	1.489.308		1.299.571	
7	75.571	4.534.316	997.549		851.151	
8	37.518	2.251.119	495.246		413.049	
9	48.393	2.903.623	638.797		520.701	
10	46.380	2.782.859	612.229		487.831	

2.10 Comparison of the simulation results

In **Figure 2.12** a performance comparison of the four optimum Chemical EOR scenarios that were simulated, is illustrated. It can be seen that by adding Surfactants or Alkalis in the Polymer flooding then an increase in the incremental oil recovery is observed. Despite of the fact that in the specific reservoir and under the given circumstances could not be taken full advantage of the synergy effect, ASP flooding still demonstrates the highest oil recovery potential. In **Figure 2.13** a comparison chart in terms of Net Present Value is illustrated where the economic advantage of the Polymer and A-P flooding methods is illustrated.
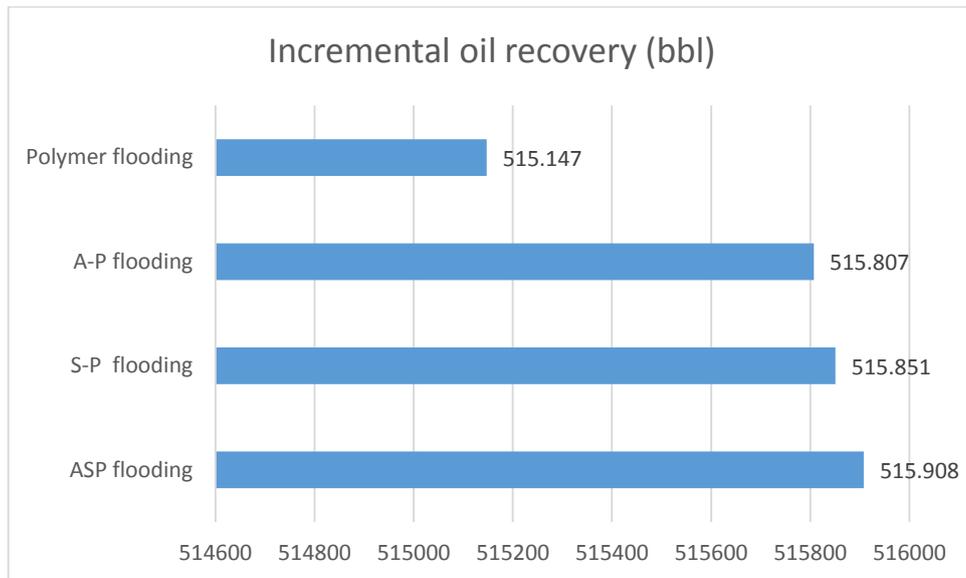

**Figure 2.12:** Comparison chart of the simulated Chemical EOR methods in terms of incremental oil recovery
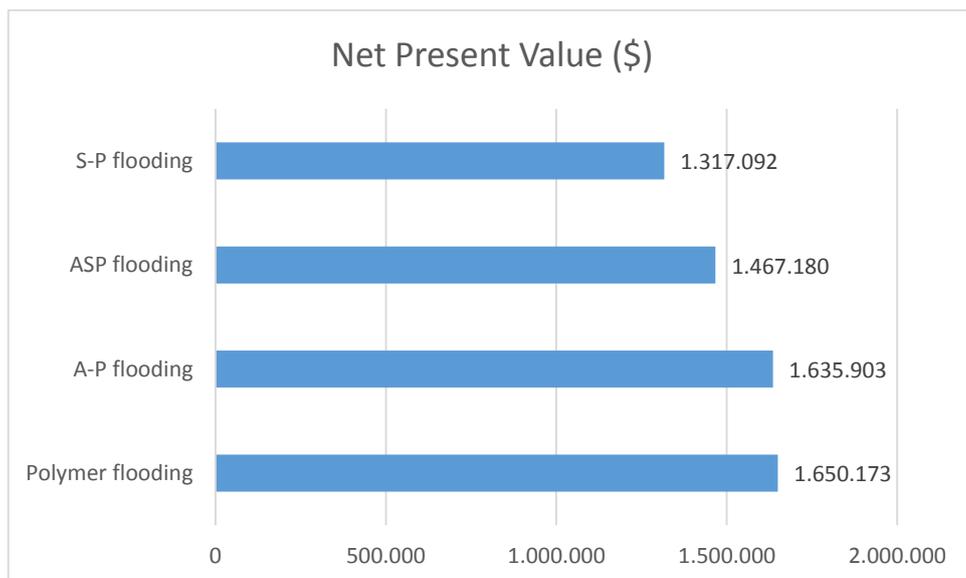
Figure 2.13: Comparison chart of the simulated Chemical EOR methods in terms of incremental oil recovery

2.11 Conclusions

H1 Segment of Gullfaks oil field is an offshore, highly heterogeneous oil reservoir. For the specific case if a Chemical EOR method is going to be implemented, Polymer flooding must be the best choice. For the present simulation study, a fixed cost of 50.000 $ /month was assumed for the storage and treatment facilities of all the different methods. It is obvious that when using different types of chemicals this cost is increasing as they must be stored separately. The lack of available space is also a characteristic of the offshore installations. Furthermore, the relative long distance the injected slugs have to cover due to the wide well spacing do not permit the exploitation of the synergy effect of the different chemical compounds as the integrity of the chemical slug is disrupted. For the above reasons, Polymer flooding is recommended as the Chemical EOR method with the highest potential of successful implementation in the specific oil field.

2.12 References

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