ENHANCED OIL RECOVERY OF HEAVY OIL BY USING THERMAL AND NON-THERMAL METHODS

by

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Submitted in partial fulfilment of the requirements
for the degree of Master of engineering

at

Dalhousie University
Halifax, Nova Scotia
March 5, 2012

DALHOUSIE UNIVERSITY

FACULTY OF ENGINEERING

PETROLEUM ENGINEERING PROGRAM

The undersigned hereby certify that they have read and recommend to the Faculty of Graduate Studies for acceptance a thesis entitled "ENHANCED OIL RECOVERY OF HEAVY OIL BY USING THERMAL AND NON-THERMAL METHODS" by Syed Ata Abbas Naqvi in partial fulfilment of the requirements for the degree of Master of M.Eng.

Dated: March 5,2012

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DALHOUSIE UNIVERSITY

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DEPARTMENT OR SCHOOL: Petroleum Engineering

DEGREE: M.Eng. CONVOCATION: May YEAR: 2012

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DEDICATION

I dedicate my work to my parents who have always been helpful and guided me towards the right way without them I would never have achieved everything in my life. The moral support from my brothers also helped me a lot. I am always thankful to The Almighty for blessing me with such a caring family.

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ABSTRACT

World's conventional oil reservoirs are depleting on an alarming rate and we must find alternate sources to keep the supply undisturbed. Currently the best alternative is the heavy oil which can be extracted by applying different techniques which are different from the conventional methods. Alberta holds the world's largest reserves of bitumen. This paper deals with the techniques for enhance oil recovery which include thermal and non-thermal methods, along with the projects going on in different parts of the world especially in Canada. Potential of new technologies is assessed and their comparison with already existing technologies is also the focus of this paper. Better understanding of methods may help in the method selection. Facts and figures obtained from different oil fields of the world are also discussed in this report. A few other methods which were tried in past and did not work as desired are also discussed because there is always a potential for further development. Every method is unique and has its limitations; an effort has been made to address those problems and their rectification.

LIST OF ABBREVIATIONS USED

cP.	Centipoise.
API.	American Petroleum Institute.
CHOPS.	Cold Heavy Oil Production with Sand.
PPT.	Pressure Pulse Technology.
VAPEX.	Vapor-Assisted Petroleum Extraction.
TEOR.	Thermally Enhanced Oil Recovery Methods.
SAGD.	Steam-Assisted Gravity Drainage.
LTO.	Low Temperature Oxidation.
CO2.	Carbon Dioxide.
H2S.	Hydrogen sulfide.
pH.	Power of Hydrogen.
COFCAW.	Combination Of Forward Combustion And Water Flooding.
Bbl.	Barrel.
THAI.	Toe-to-Heel Air Injection.
MWD.	Measurement While Drilling.
PV.	Pore Volume.
md.	MilliDarcy.
OIP.	Oil in Place.
OOIP.	Original oil in place.

ACKNOWLEDGMENTS

All praises are for The Almighty, the most Beneficial and the most Merciful.

I would like to extend my gratitude to Dr. Michael. J. Pegg who supervised my worked and guided me throughout my degree program. I am also thankful to Dr. Dominic Groulx who added his comments and corrected me where required.

CHAPTER 1 INTRODUCTION

1.1. HEAVY OIL

Compared with conventional oil, heavy oil has reduced mobility; it is termed as heavy oil because it has higher specific gravity and density along with viscosity when compared with the conventional oil. The viscosity is between 100 cP or greater and API gravity less than 20°. API gravity is a Specific gravity scale developed by the American petroleum institute to measure the relative density of various petroleum liquids, expressed in degrees. The lower the API number, the heavier the oil and the higher its specific gravity.

Goodarzi et al., (2009) define heavy oil in terms of viscosity as the class of oils ranging from 50 cP to 5000 cP. The high viscosity restricts the easy flow of oil at the reservoir temperature and pressure. Figure-1 is a graph relating viscosity and API ratings and it can be observed that the heavy oil region lies in the high viscosity range.

Ancheyta and Speight (2007) define heavy oil as a viscous type of petroleum that contains a higher level of sulfur as compared to conventional petroleum that occurs in similar locations.
Meyer et al., (2007) explained that the oil becomes heavy as a result of eradication of light fractions through natural processes after evolution from the natural source materials. A high proportion of asphaltic molecules and with substitution in the carbon network of heteroatoms such as nitrogen, sulfur, and oxygen also play an important role in making the oil heavy. Therefore, heavy oil, regardless of source, always contains the heavy fractions of asphaltenes, heavy metal, sulphur, and nitrogen.

The importance of resins and asphaltenes in accumulation, recovery, processing, and utilization of petroleum was highlighted by Raicar and Proctor (1984). They found that most asphaltenes are generated from the kerogen evolution due to the increase in temperature and pressure with the increase in depth. Their opinion is in the light of the fact that asphaltenes are recognized as a soluble chemically altered fragments of kerogen that migrated out of the source rock during oil catagenesis.

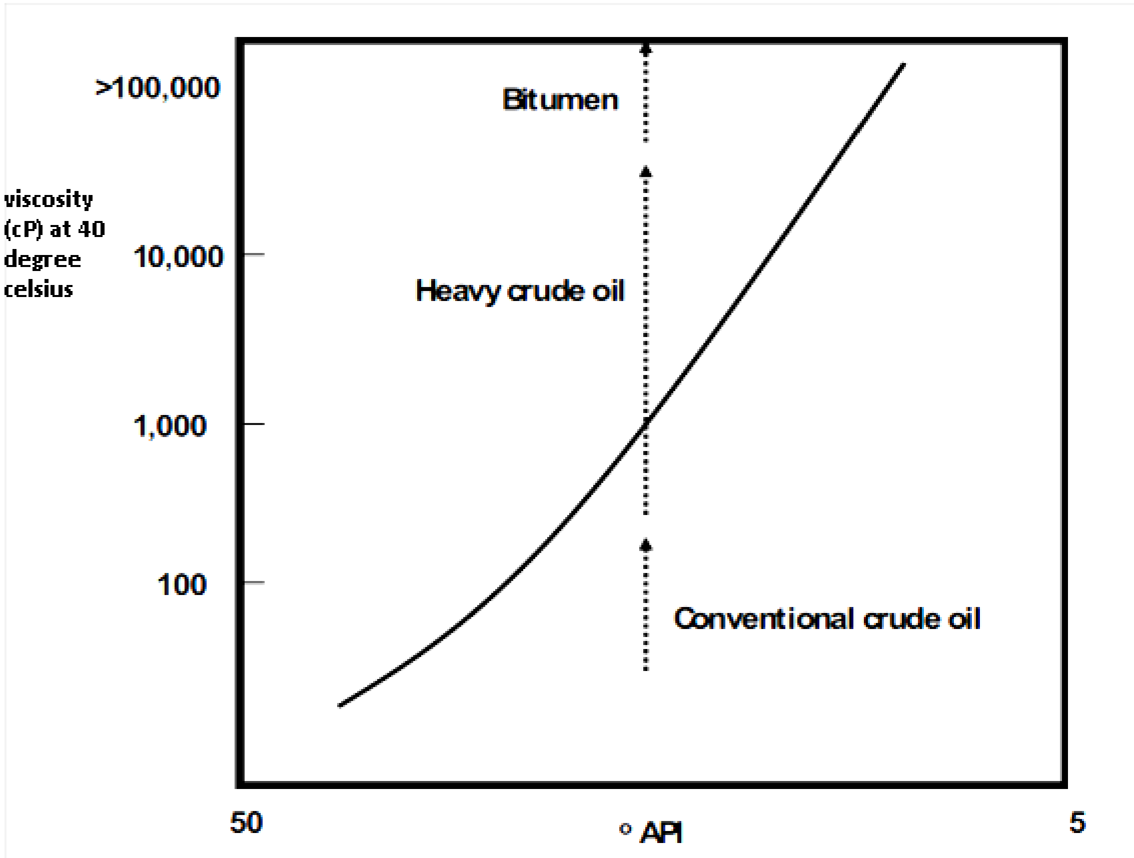


Figure1 General relationship of viscosity to API gravity. [Thomas, 2008]

1.2. ORIGIN

Origin of heavy oil according to many authors is the result of biodegradation. Larter et al., (2006) believes that first the oil was expelled from its source rock as light or medium oil , and subsequently migrated to a trap, then it is converted into heavy oil through different processes such as water washing, bacterial degradation (aerobic), and evaporation, provided that the trap is elevated into oxidizing zone. This biodegradation can occur at the depth in a subsurface reservoir. Head et.al, (2003) mentioned the depths of the biodegradation oil up to about 4 Km with most biodegraded reservoirs up to 2.5 Km below the sediment surface.

From the above we can conclude that the heavy oil migrated from the deep source rock or deep reservoirs originally as conventional oil. At these depths, water caused weathering and bacteria fed on the oil causing biological degradation by removing hydrogen and thus increasing its density.

1.3. HEAVY OIL RESERVOIRS

Heavy oil is reasonably mobile in the reservoirs which have sufficiently high temperature due to which heavy oil can be produced by using conventional methods. Figure-2 shows the typical oil sand grain. The figure explains how each grain is surrounded by a layer of water and bounded by bitumen.

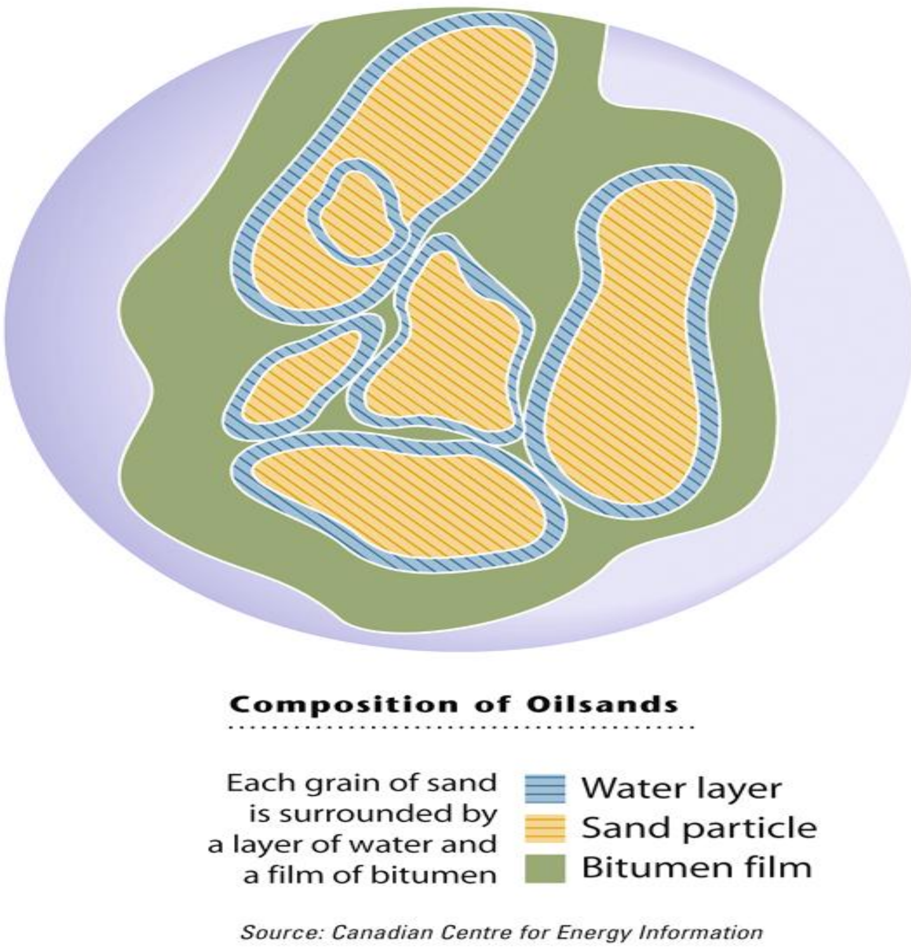


Figure-2 Oil-sand grain structure [Canadian centre for energy information]

The reservoirs of heavy oil are shallow and have less effective seals (up to 1000 meters below the surface line), which is the reason for the low reservoir temperature (40-60 °C). Low sedimentary overburden tends to ease the biodegradation, and the presence of the bottom aquifers further facilitates the process. As mentioned earlier the less effective seal is due to the low seal pressure, which may cause the dissolved gases to leave the oil, increasing its viscosity. The reservoir lithology is usually sandstones deposited as turbidity with high porosity and permeability; the elevated viscosity is compensated by high permeability.

1.4. HEAVY HYDROCARBONS AS AN ALTERNATIVE SOURCE OF PETROLEUM

Hydrocarbon resources of heavy oil and oil sands are nearly three times the conventional oil in place in the world. According to Farouq Ali and Meldau (1999) over two trillion barrels of oil is present in the oils sands of Alberta and in Canada the contribution of heavy oil and oil sands resources is 20% of the total oil production.

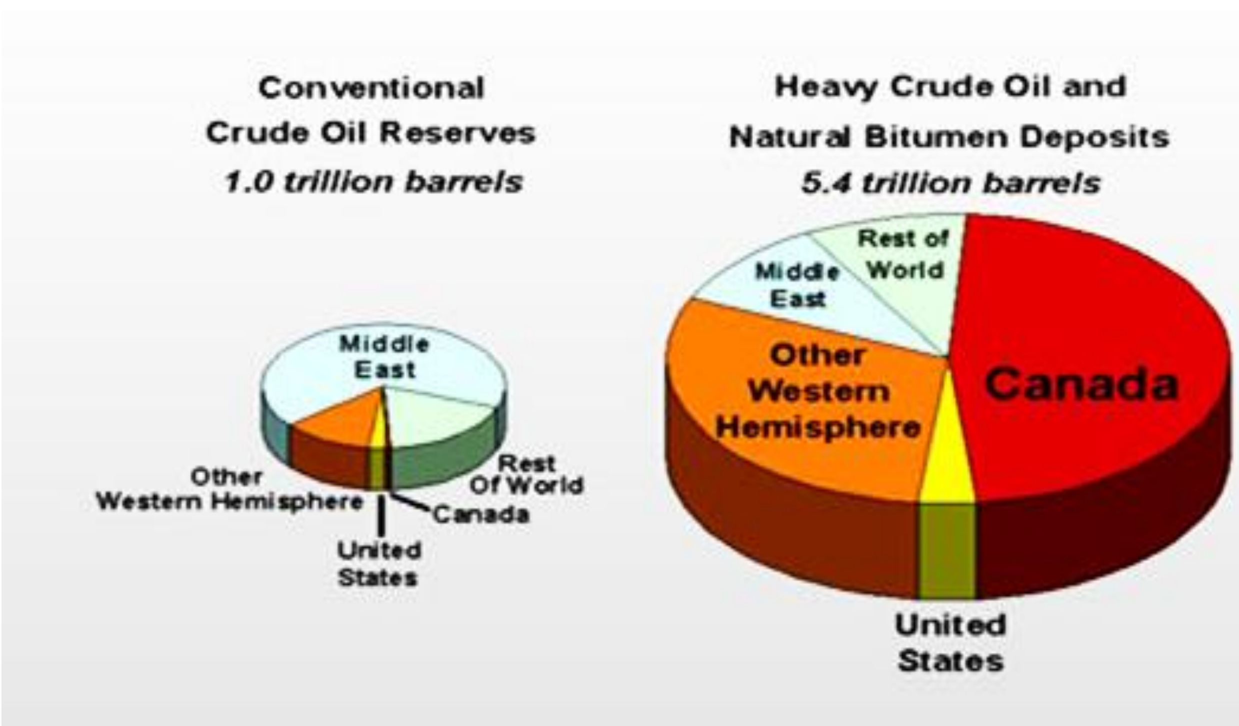


Figure-3 Distribution of conventional crude oil and heavy hydro carbons [Herron, 2000]

Herron in his article “Heavy Oil: A Solution to Dwindling Domestic Oil Supplies” wrote that the total estimate of worldwide deposits of heavy hydrocarbons is around 5½ trillion barrels and western hemisphere contains four-fifths of these deposits. From the crude distribution showed in figure-3 we can conclude that the outlook for domestic oil supplies can be much improved if the heavy oil hydrocarbon resources (both heavy crude oil and natural bitumen) are included in petroleum sources.

1.5. CANADA’S HEAVY OIL INDUSTRY

Canada along with Venezuela holds 90% of the world’s heavy oil and bitumen (oil sands). The largest reserves of bitumen are located in Alberta. The resources of the conventional crude oil in Canada are declining which opens the window for further development of technologies to recover heavy oil. These technologies are discussed in this report. Canada’s present and future energy requirements heavily rely upon the breakthrough in these technologies.

Figure-4 shows Canada’s heavy oil resources which are in northeastern Alberta and western Saskatchewan. In past ten years Canada’s heavy oil industry has experienced a remarkable resurgence, much of which is due the technological advancements.

A number of different projects are in progress in the areas shown in figure-5. In those fields sands are un-cemented with high porosity and permeability. The viscosities of oil range are from few hundred to more than a million cP with 20° to 8° API gravity. The reservoirs are shallow, the solution gas content is low and pressure and temperature are towards the lower side as well. Recoveries were usually limited to 3-5% of the oil in place when early attempts were made to produce from these oils. The reasons for the low recovery were:

1. Low flow rates resulting from the high viscosity.
2. Problems with sand construction.
3. Water breakthrough.

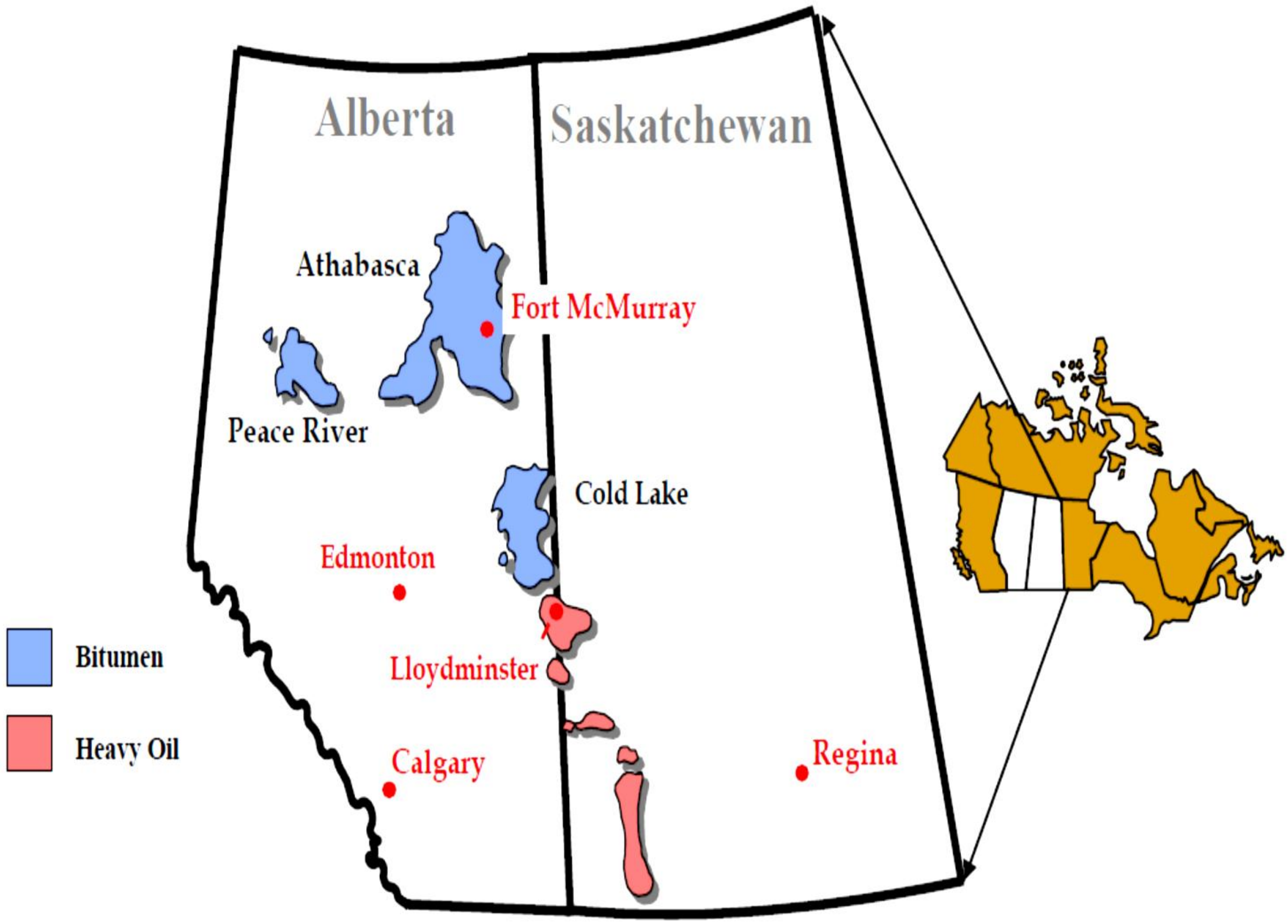


Figure-4 Major oil Sand Deposits of Canada [Nasr and Ayodele, 2005]

But technological wonders such as Horizontal wells, progressive cavity pumps, foamy oil/sand production, and other methods, along with horizontal drilling has solved the above mentioned problems. As significant improvements were seen in both primary and enhanced recoveries which result in better producibility and improved the level of heavy oil recovery considerably.

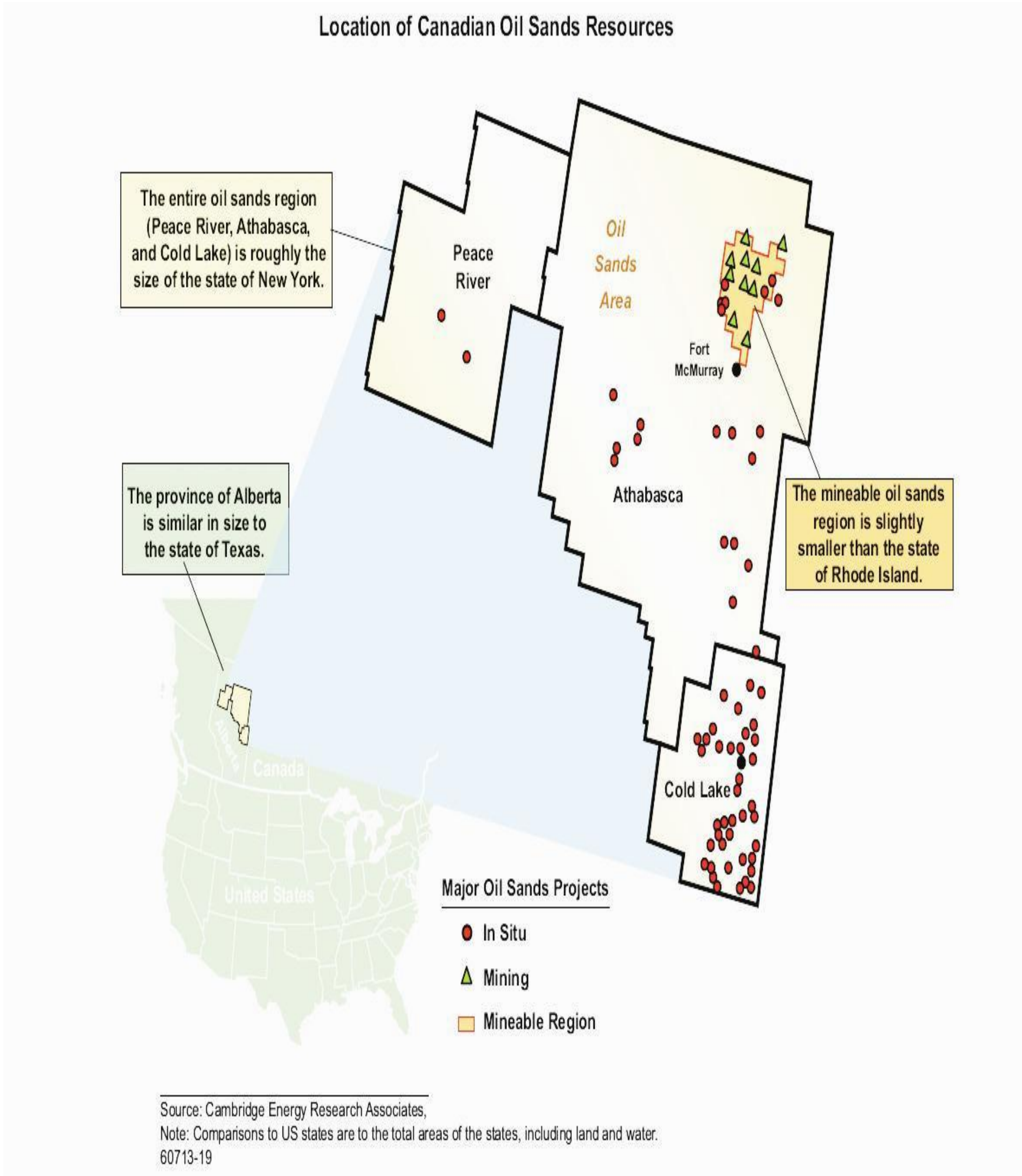


Figure-5 Major oil sands project locations in Canada

Figure-6 shows the oil production forecast for Canadian crude oil by Nasr and Ayodele (2005). This prediction was made by keeping in mind the current production and the projects carried out in western Canada and as shown in Figure-6 the heavy oil industry will be the biggest contributor of the Canadian crude oil in future.

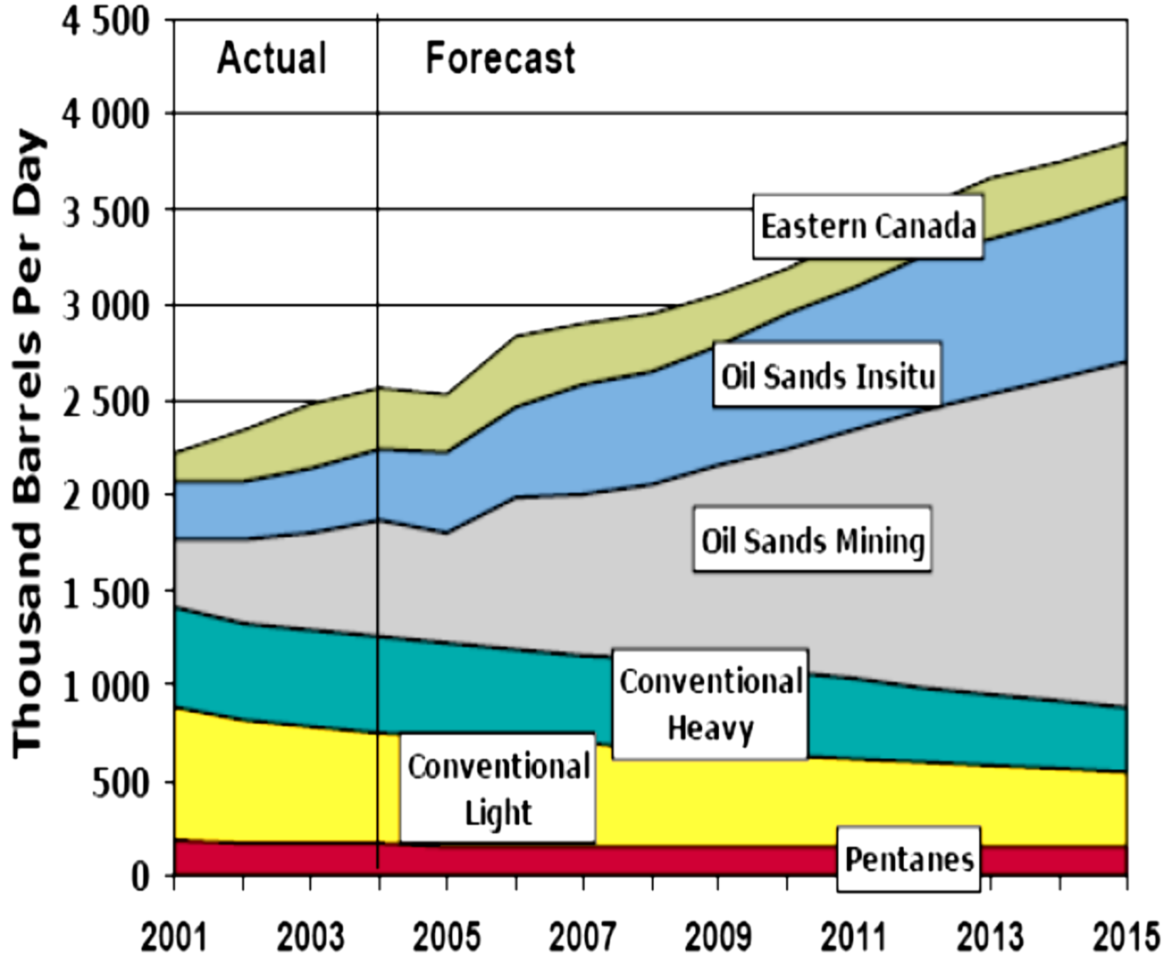


Figure-6 Canadian Crude Oil Production forecast (moderate estimate) [Nasr and Ayodele, 2005]

CHAPTER 2 NON-THERMAL PRIMARY RECOVERY METHODS

As discussed earlier, many heavy oil reservoirs contains oil that does not flow easily under reservoir conditions which means successful recovery of this resource is based upon developing a mechanism that displaces the heavy oil in the reservoir. All reservoirs have different lithology and some of them are thin or small and overlying gas or underlying water may cause contraction in them which makes them poor candidate for the thermal methods of oil recovery. That means after the application of primary recovery any additional method should be non-thermal.

Primary recovery techniques rely entirely on natural forces within the reservoir that's why it is not the usual approach of recovery. For example the pressure of natural gas dissolved in oil or present above the oil or the natural pressures surrounding the reservoir rocks can help in the flow of oil. Figure-7 shows different methods and the basic techniques of primary recovery.

These techniques are mostly used to recover conventional oil as compared to heavy oil which depends upon the fluidity of oil in the reservoir. The amount of oil that is recoverable depends upon the reservoir temperature and the permeability of the rocks. A high temperature in the reservoir increases the fluidity. Permeability of rocks can be understood by considering the example of reservoir rocks which are "tight", such as in shale in which the flow of oil is restricted, but oil flows more freely in the case of permeable rocks such as sandstones.

Meyer and Attanasi (2003) mentioned several very large projects which produce more than 100,000 barrels per day for heavy oil of approximately 12° API. In the Heavy Oil Belt (FAJA) in Venezuela the recovery yield from primary methods is 8 to 15%. It is expected that the heavy oil production from this belt will last for 35 years at a production rate of 600,000 barrels per day. Firozabadi (2001) stated that the recovery from primary production in heavy oil reservoirs may be as high as 20 %; the factors that make it possible will be discussed later.

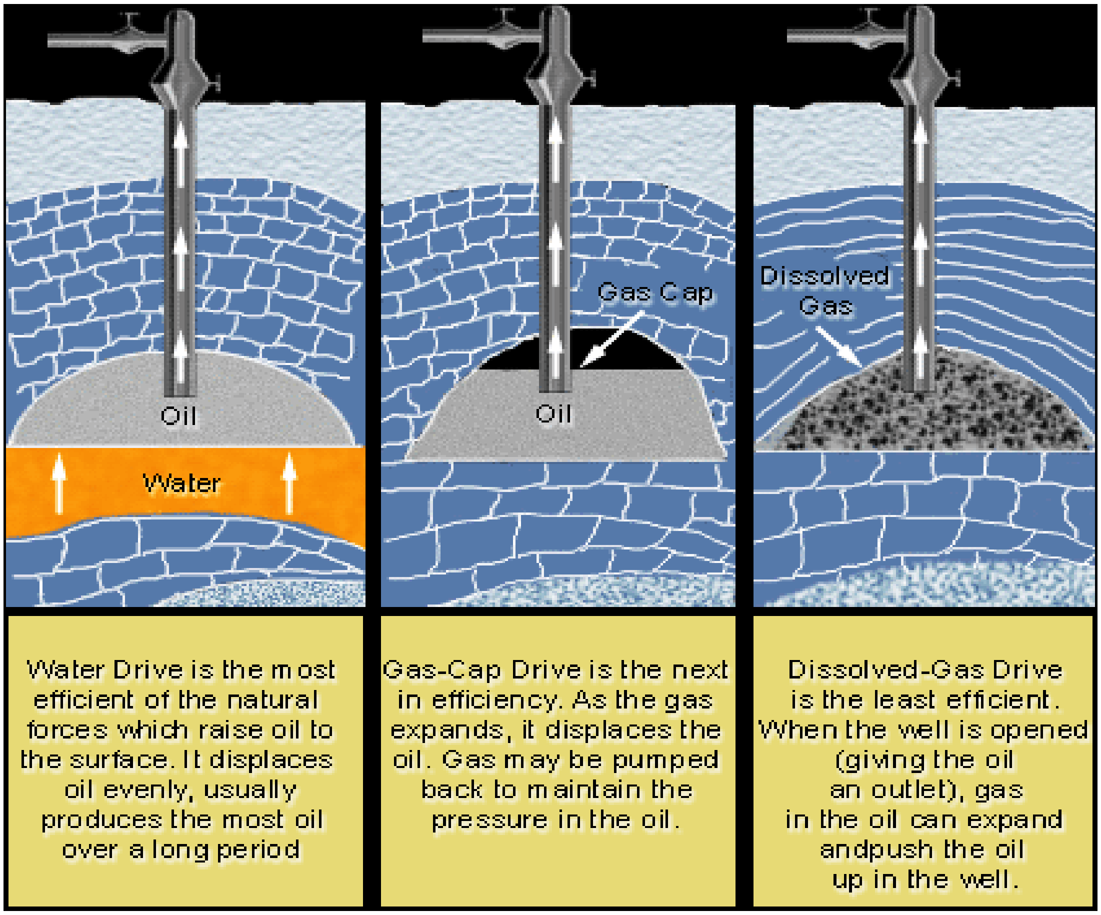


Figure-7 Three basic natural drives [Tendem-terminal]

2.1. WATER DRIVE

Water drive is the most efficient naturally driven propulsive force drive, it drives the oil into a well by pressurizing recoverable oil with the help of forces of water (as shown in figure-8). In water drive field it should be taken care that the removal rate should be adjusted, so that water moves up evenly and there is always an available space for it by the removal of hydrocarbons. Figure-8 shows an anticlinal structure, the flanks are the first ones to come in contact with water.

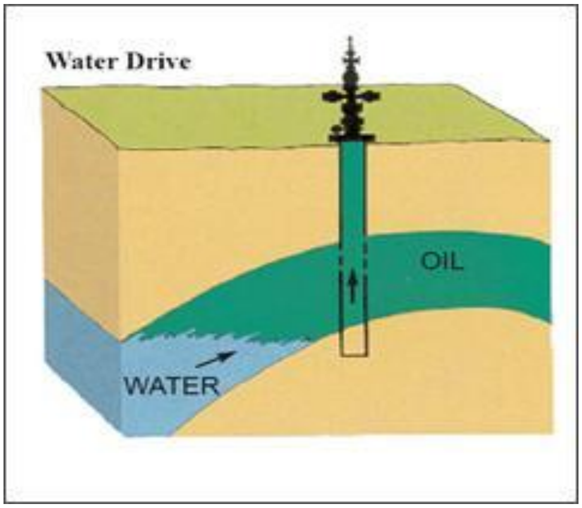


Figure-8 Water drive [Thomas, 2008]

This is the most efficient process in driving the oil into a well; it works by pressurizing the light recoverable oil with the help of forces of water in a water drive field. In an anticlinal structure, first the lowest wells around and then the oil-water plane moves upward as they produce until it reaches the top of the anticline. An appreciable decline in bottom-hole pressure is necessary when the well is abandoned as it displaces the oil. This pressure decline provides the pressure gradient to cause water influx. The pressure differential depends upon the permeability, which means less pressure is required for greater permeability to cause the water influx. The recovery from the properly operated drive pools can be as high as 80%. The force behind water drives may be either the expansion of reservoir water or hydrostatic pressure or a combination of both.

2.2. GAS CAP DRIVE

The gas if it lies over the top of the trap with oil beneath it can be utilized to drive the oil into wells at the bottom of the oil bearing zone (as shown in figure-9). The gas (usually methane and other hydrocarbons) is compressed to achieve this condition. This process is known as the gas cap drive. If the oil is produced only from below if the gas cap than it is possible to achieve high gas-oil ration in the reservoir.

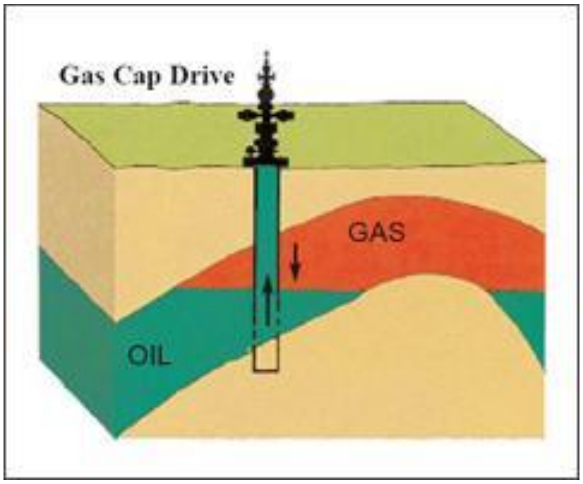


Figure-9 Gas-cap drive [Thomas, 2008]

In this kind of recovery an undue portion of oil is left behind because the oil deposits are not systematically developed, which causes the bypassing of gas. The gas mixture (methane and other hydrocarbons) may be separated by compressing the gas. Gasoline is an example of the gases that are separated by compression of gases. However, at high pressures retrograde condensates are formed, because in deeper fields the density of oil decreases and the density of gas increases until they form a single phase. The retrograde condensate pools bring condensation in Liquid hydrocarbons because the pressure declines instead of inclination. When this condensate is removed from the reservoir fluid, the pressure is maintained within the gas cap by injecting back the residual gas into the reservoir.

2.3. SOLUTION GAS DRIVE OR DISSOLVED GAS DRIVE

In Solution gas drive, the propulsive force comes from the gas dissolved in the oil (as shown in figure-10), this force is the result of pressure release at the point of penetration in the well. It means that release of gas expansion from the 'oil in place' fluids, as the reservoir pressure declines, supplies the major reservoir energy for the primary depletion. The fraction oil in place decreases with the increase in oil viscosity.

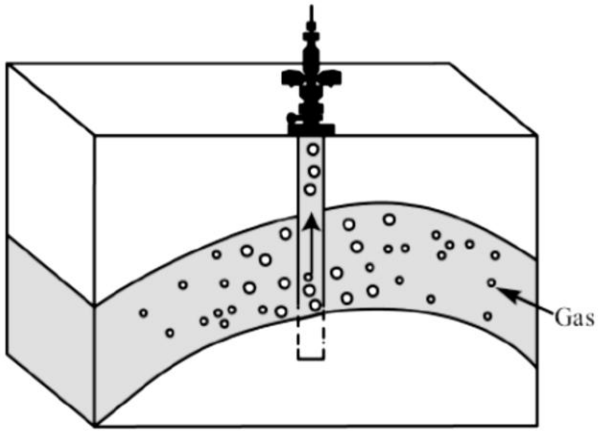


Figure-10 Solution gas drive [Thomas, 2008]

Thomas 2008 explained that the Solution gas drive is the mechanism whereby lowering of the reservoir pressure through production in an under-saturated reservoir causes the oil to reach the bubble point where gas starts to evolve from solution.

The definition from Thomas (2008) is valid when the evolved gas begins to flow only when the critical gas saturation has been reached. Once that condition is achieved, then it will cause an increase in the rate of pressure drop due to the production of the gas phase. All of the evolved gas below the bubble point pressure is kept in the form of small bubbles in the porous media and does not form a continuous free gas phase. Retention of the evolved gas phase in a dispersed form with the oil would lead to maintaining the reservoir energy.

A number of heavy oil reservoirs under solution gas drive, however, have obtained anomalous primary performance results which are:

1. Low production gas-oil ratios.
2. High oil production rates.
3. Recovery of unexpectedly large amounts of oil.

This unusual behavior as explained by Chen 2006 has been attributed to:

- **The foamy character of oil** which is due to the expansion of gas bubbles; these bubbles are trapped by the oil and enhance recovery by solution. Chen 2006 also concluded that the ultimate oil recovery with primary techniques can be as high as 20% for some heavy foamy oil reservoirs.
- **Internal erosion** which can create a network of high-permeability channels (wormholes) in unconsolidated reservoirs and enhance drainage.

2.3.1. Comparison of solution gas drive with all natural drives

If we compare solution gas drive with other natural drives than it is observed that solution gas drive is the least efficient type of natural drive and water drive is the most efficient of all. Solution drive is the least efficient because it is very difficult to control the gas-oil ratio. The bottom hole pressure drops, and in the end the total recovery from the reservoir may be less than 20%.

CHAPTER 3 NON-THERMAL SECONDARY RECOVERY METHODS

A lot of oil can be left behind after primary recovery, since the normal reservoir pressure has declined and as a result there is no natural force that can push the oil into the well that's why secondary methods come into play. Secondary oil recovery techniques are applied on depleted or low pressure reservoirs. Some of the techniques are discussed below.

3.1. WATER FLOODING

In water flooding the energy required to drive the oil from the reservoir rock is provided by means of water injection from the surface as shown in figure-11. Water injection boosts the low pressure in the reservoir keeping the production rate and the pressure the same over the long term, hence producing the oil replacing by the water. Water flooding was considered to be a form of enhanced oil recovery but it is essentially an artificial water drive.

The theory of water flooding is quite old in industry and according to Smith (1992) this theory was pioneered by Buckley and Leverett. In their theory, displacement starts with only connate water and oil as incompressible phases. A region divided by the shock front in which only movable oil which is being displaced, from the one with only movable water. Only oil is produced prior to breakthrough and only water after.

In a completely developed oil field, the wells may be drilled anywhere from 200 to 2,000 feet (60 to 600 meters) from one another, depending on the nature of the reservoir. If water is pumped into alternate wells in such a field (consider figure-12), the pressure in the reservoir as a whole can be maintained or even increased. Water flooding may increase the recovery efficiency to as much as 60% or more of the original oil in place. Kumar (2006) reported incremental recovery of approximately 2 to 20% of the original oil in place.

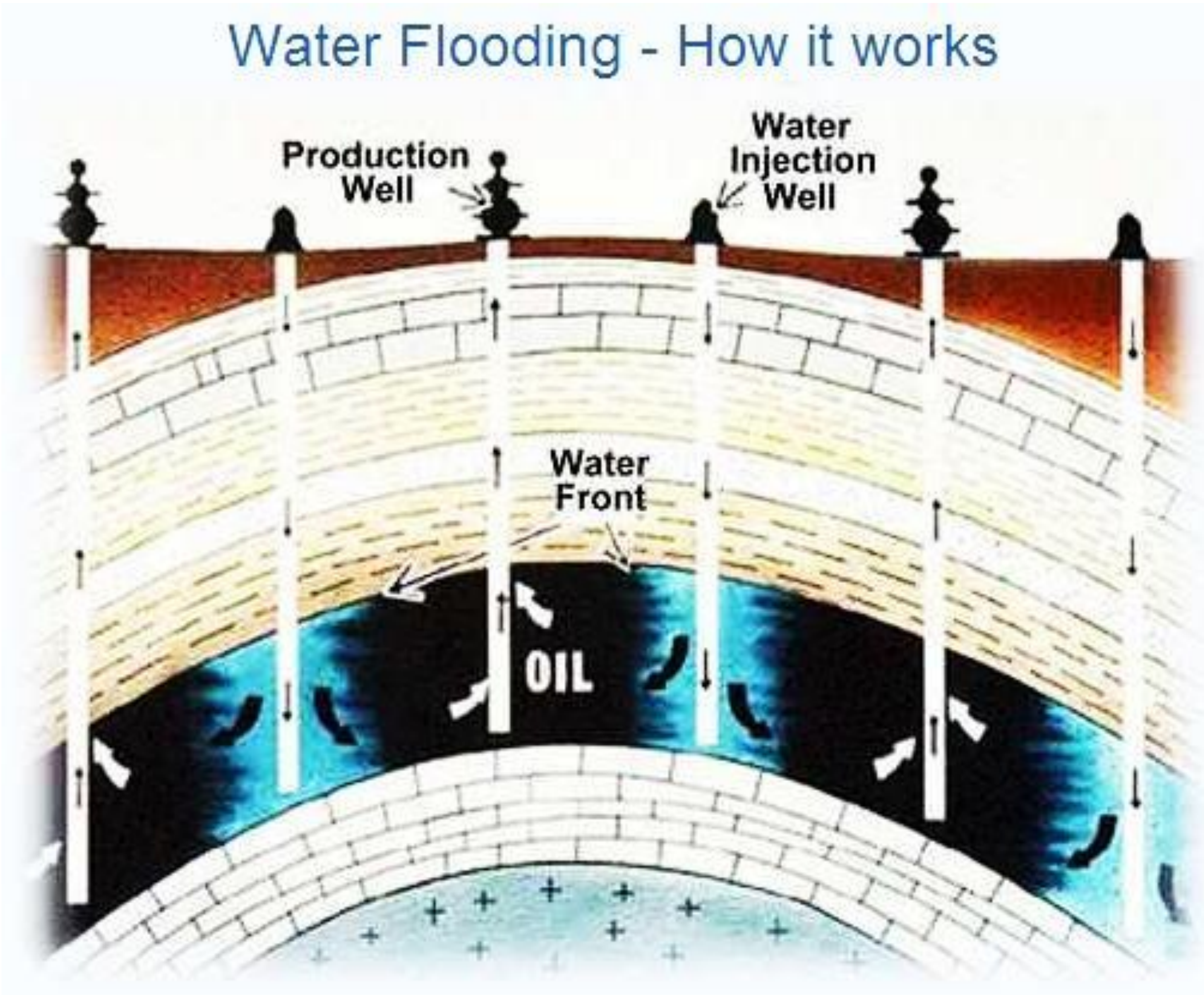


Figure-11 Water flooding displacing oil [newenergyandfuel.com]

As discussed earlier, Buckley & Leverett postulated in their theory that only connate water can be used. But now we know that any and every source of bulk water can be used for injection, produced water is specially used as an injection fluid because its biggest advantage is that, it reduces the potential of causing formation damage due to incompatible fluids; however, the risk of corrosion in injection flow lines or tubing remains. It should be kept in mind that the produced water should be treated and cleaned up for contamination of the solids and hydrocarbons, before disposing off to sea.

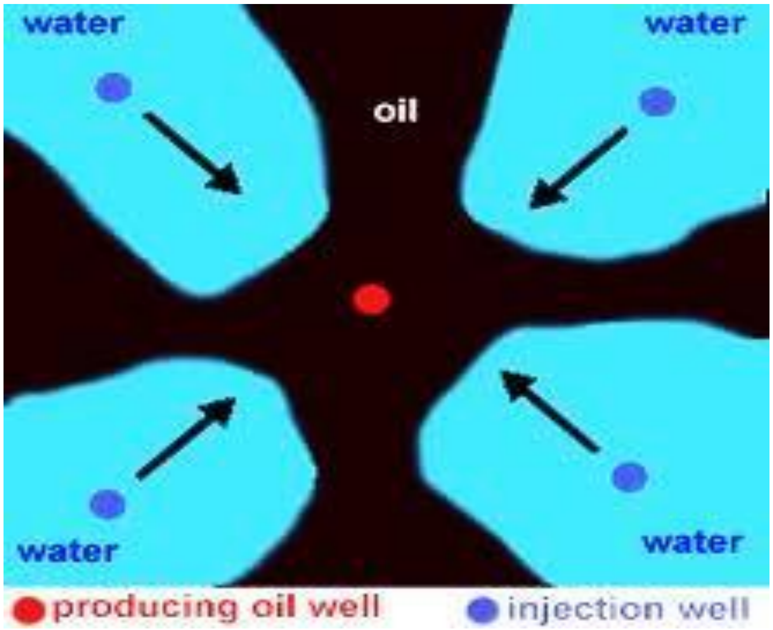


Figure-12 Concept of water flooding [Markes, 2001]

Aquifer water from water-bearing sources can be used, as the volumes of water are never sufficient to replace all the production volumes (oil and gas, in addition to water). Aquifers are used as a source of "additional make-up" water because it is pure compared to the river water, which requires treatment like filtration and biociding. For offshore facilities there is no better choice than sea water after the removal of oxygen from the water because it promotes corrosion and helps in the growth of certain bacteria which can choke the pores in the rock and is also responsible for the production of hydrogen sulfide.

3.2. COLD PRODUCTION

In this method sand is produced aggressively along with the heavy oil without applying heat. The oil production is improved substantially through the regions of increased permeability wormholes. The basis of this process is the oil production and recovery when sand production occurs naturally. The production of the unconsolidated un-cemented reservoir sand results in significantly higher oil production.

Sawatzky et al., (2002) postulated that oil production and sand production are bound together intimately in the process. What these authors means can be described in a three step process

- **First Step:** The mobile heavy oil flows toward the production well, sharp pressure gradients are generated in the reservoir.
- **Second Step:** This results in failure of the unconsolidated sand matrix.
- **Third Step:** The failed sand is dragged to the well by the high viscosity oil.

Tremblay and Sedgwick (1999) agreed to Sawatzky et al., (2002) and they believe cold heavy oil production with sand (CHOPS) is now widely used as a production approach in unconsolidated sandstones. The production of sand from an unconsolidated heavy oil reservoir generates a network of high permeability channels known as wormholes that grow into the reservoir (as discussed earlier).

As a result of sharp pressure gradients as described by Sawatzky et al., (2002) , sandcuts are generated which according to Chugh et.al, (2000) can be as high as 40% in the first days of production dropping to 1-2% in the long term.

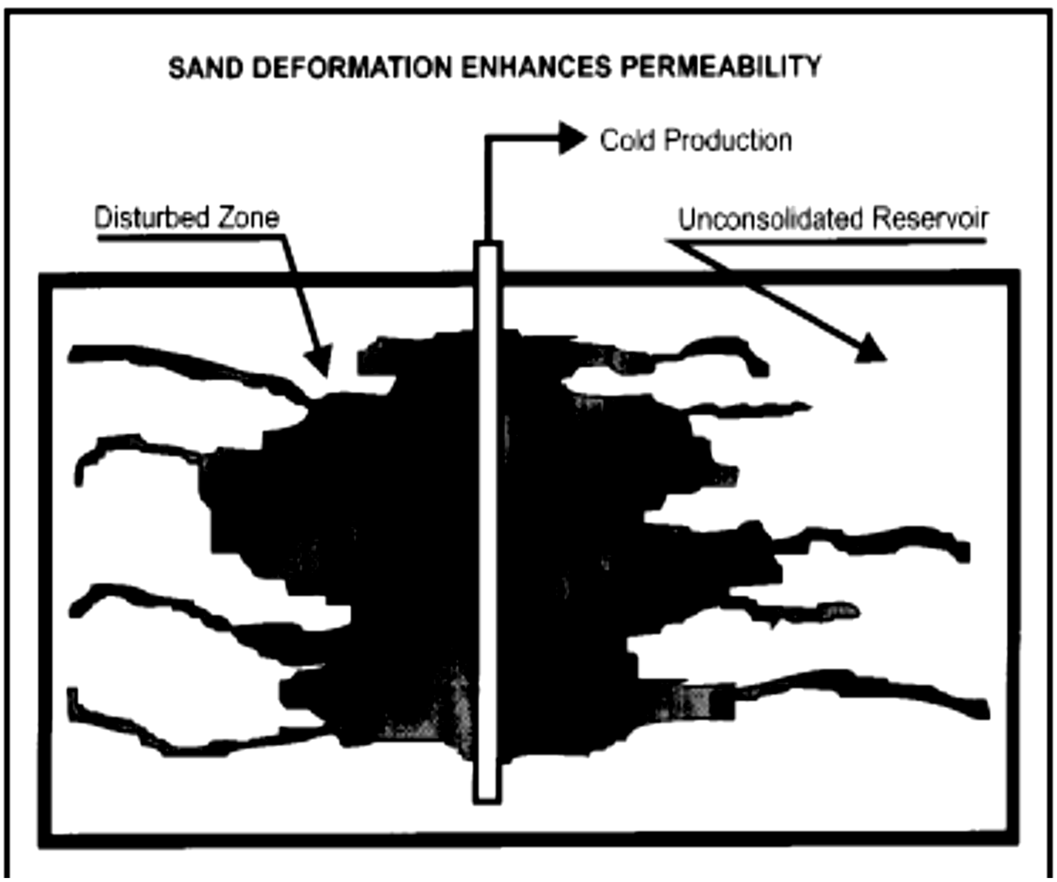


Figure-13 Schematic of sand production with wormholing [Chugh et al., 2000]

Sand production is thought to be a function of the following according to Chugh et al., (2000).

- **The absence of clays and cementation materials:** as the presence of clay stabilizes the sand grains which reduce sand movement.
- **The viscosity of the oil:** because higher oil viscosity increases the frictional drag between the oil and the sand grains, which promotes sand movement.
- **The producing water cut and gas/oil ratio:** because water and the sand grains inhibit sand movement.
- **The rate of pressure drawdown:** increasing the drawdown rate also promotes sand movement because the increase in the velocity of the fluid in the well bore will increase the frictional drag on the sand grains.

Now let us see how sand production and sand removal can increase the productivity.
This process increases the productivity due to the following reasons:

- **Sand grain flow**: the flow of sand with the oil has the potential to reduce the frictional drag (as earlier discussed), which could increase the productivity in the sand flowing region.
- **Sand removal**: as the sand is removed it makes the way for the overburden weight to act as a shear and destabilize the sand, helping to drive the sand and oil towards the wellbore.
- **Enlarge the drainage radius**: the produced sand creates a modified wellbore geometry that could have several configurations including wormholes (as discussed earlier) and a significant increase in permeability due to an increase of porosity in the dilated zones.
- **Foamy flow**: gas coming out of the solution in the heavy oil in the form of bubbles which do not coalesce, but expand down gradient, this is called as a foamy flow. This helps to locally destabilize the sand and sustaining the process.
- **Liberation of the pore blocking minerals:** pore throats can be blocked by fines migration that occurs during the oil production. This blockade reduces the number of flow paths available for the oil flow, dilation of sand creates the larger pore throats which eliminates the blockade because it is very difficult to block those pore throats.
- **Clean up drilling damage**: there is one more blockage, which is between the wellbore and the sand face caused by the drilling mud and the drilling fines. Producing sand

adjacent to the well is an effective means of cleaning up the damage. The continuous sand production means the asphaltenes or fines plugging of the near well-bore environment does not occur, so there is no possibility of an effect to impair productivity.

3.2.1. Conclusion on cold production

By studying the whole process it can be concluded that the cold production can be summed up succinctly as a process in which the well is transported to the oil rather than the oil transported to the well.

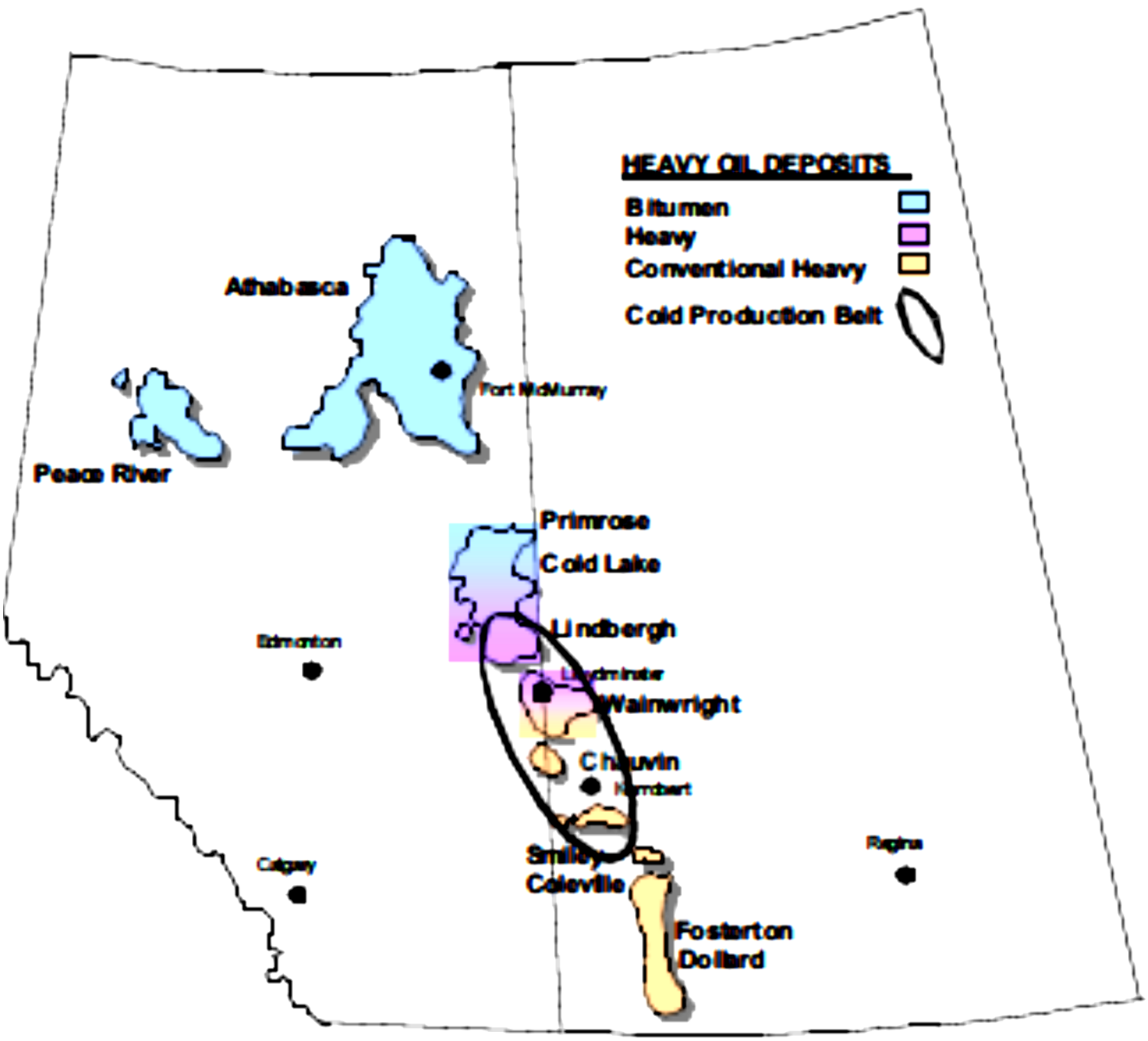


Figure-14 Heavy oil deposits in Alberta and Saskatchewan, with an indication of the cold production belt surrounding Lloydminster [Swatzky et al., 2002]

3.3. GAS INJECTION

The process also known as reinjection or re-pressurization increases the pressure in the reservoir by gas injection and thus induces the flow of crude oil. The injected gas molecules dissolved in the oil reduce its viscosity and make it mobile which increases the well output. After the crude oil is pumped out, the natural gas is once again recovered. Carbon dioxide is used as the gas for re-pressurization. Inert gases, and natural gas can also be used to pressurize the well, but air is not suitable for that because it causes deterioration of the oil.

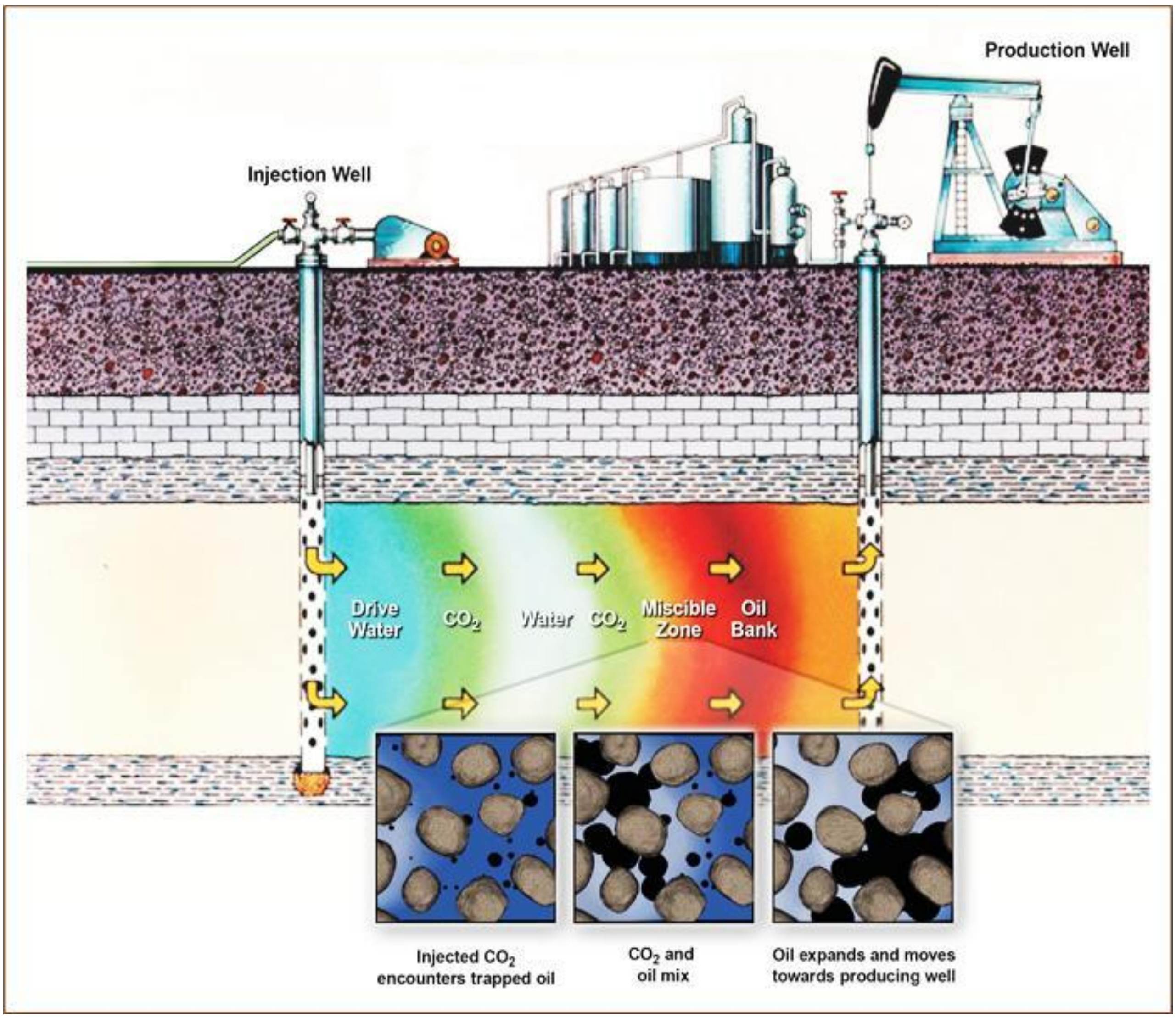


Figure-15 Schematic for miscible enhanced recovery processes [netl.doe.gov]

Figure-15 shows the process of carbon dioxide injection .Carbon dioxide injection reduces the emission of Co_2 in the atmosphere, making it a form of carbon sequestration. This has been promoted as a major weapon in the future fight against climate change, as it allows mass storage of Co_2 over a geological timescale.

3.4. PRESSURE PULSE TECHNOLOGY

Rovers (2003) define Pressure pulse technology (PPT) as the technology that can be used to reduce solid clogging in wells and enhance the recovery rate. This technology works generating large amplitude pressure pulses dominated by low frequency wave energy that helps in improving flow rates in the porous media so basically this technology uses non seismic pulse vibration that generate a low velocity wave effect, which encourages the flow of oil and solid particles.

It is basically the generation of a porosity dilation wave, also called a fluid displacement wave, which is similar to a tidal wave. This produces pore scale dilation and contraction, the porosity dilation wave moves through the porous medium at a velocity of about 50 to 100 feet per second (15 to 30 meters per second), each packet of wave energy helps unblock pore throats by small expansion and contraction of the pores which result in increase in the velocity of liquid flow, this also helps to overcome part of the effects of capillary blockage, so that oil and water flow into and out of pores leading to periodic fluid accelerations in the throats.

3.4.1. Conclusion on Pressure Pulse Technology

This method is best suited in geological formations, such as unconsolidated sediments and sedimentary rocks, because these type of formations exhibit elastic properties. There is one limit of using that method, that it is effective only when applied in a down-hole manner. It is found that applying pressure pulse for 5-30 hours to a blocked producing well can re-establish economic production in CHOPS well for many months and in some cases for years. Pulsing, when applied in injector wells for improving the efficiency of water flood patterns, has shown an increase in the oil production and decrease in the water cut.

3.5. SOLVENT PROCESS

This solvent process works by injecting diluents, such as naphtha or light oil, near the pump to reduce the viscosity of the heavy oil to make it flow and allow it to be more easily pumped.
This process is also called as vapex, Yazdani and Maini (2008) define Vapor-assisted petroleum extraction (VAPEX) as a non-thermal, solvent based, relatively cold (40°C), low pressure process where two parallel horizontal wells are drilled with about a 15-foot vertical separation.

The concept of injecting a solvent has been found promising for the recovery of heavy oil and bitumen. A vaporized hydrocarbon solvent, usually ethane, propane, or butane, is injected into the reservoir using a horizontal well and the diluted oil is produced through another horizontal well by gravity drainage.

The process works in the following steps:

- **First Step:** The vapor travels to the oil face where it condenses into a liquid.
- **Second Step:** The solvent mixed with the oil flows to the lower well due to gravity drainage and is then pumped to the surface.

If a pure solvent is used, the solvent vapor chamber has to be maintained at pressures lower than the vapor pressure of the solvent to prevent the extracted region from being filled with liquid. This presents a problem, the reason for that was given by Das and Butler (1995); they mentioned that for solvents such as propane and butane, the vapor pressures are often lower than the reservoir pressures.

The function of the solvents as explained by Mitchell and Speight (1973) is to extract soluble components of heavy oil, initial contact between the solvent and the oil at a low solvent-to-oil ratio will cause solubilization of the asphaltic constituents. The deposition of these constituents increases as the solvent-to-oil ratio in the later stages of the process. However, there are the usual concerns over the solvents' interactions with the reservoir minerals. Clay is known to adsorb organic solvents very strongly, and it can also pollute underground formations such as aquifers.

Yang (2005) thinks that this approach, used alone be suited only for less viscous oils because of the slow diffusion of gases and liquids into viscous oils. But he was not right because preliminary tests indicate that there are micro mechanisms that act, therefore the VAPEX dilution process is not diffusion-rate limited, which makes this process suitable for the highly viscous heavy oil and tar sand bitumen.

The key benefit of this process is the low cost of energy, it can be applied on the thin reservoirs, with bottom water or reactive mineralogy, and it also has the potential for in situ upgrading. The application of this process is from paired horizontal wells, single horizontal wells, or a combination of vertical and horizontal wells.

CHAPTER 4 NON-THERMAL TERTIARY RECOVERY METHODS

Tertiary recovery of oil begins when it is felt that the production from secondary oil recovery is not enough. Tertiary recovery process like most of the recovery processes reduces the viscosity of oil to increase in production.

But Krumrine and Falcone (1987) believe that there is a renewed interest in chemical enhanced oil recovery because of diminished reserves and advances in surfactant and polymer technology. They also believe that by greater understanding of the chemical reactions involved it is possible to get good results in the field. They suggest that the combination of chemicals should be applied as premixed slugs or in sequence.

The choice of the method and the expected recovery depend on many considerations, economic as well as technological. According to Thomas (2008) only a few recovery methods have been commercially successful, such as steam injection based processes in heavy oils and miscible carbon dioxide, provided that the reservoir offers favorable conditions for implementation of such methods.

Methods for improving oil recovery, in particular those concerned with lowering the interstitial oil saturation, have received a great deal of attention both in the laboratory and in the field. Figure-16 shows step by step process of Chemical enhanced recovery process.
From the vast amount of literature on the subject, one gets the impression that it is relatively simple to increase oil recovery beyond secondary recovery, however, we should not forget that these methods are only applied if they are cost effective, so it all depends on the market price of the oil; if it is profitable enough to extract oil, then tertiary methods are sufficiently effective to add 5%-15% more to the production. In the period when the oil prices are low, production is curtailed, and when it is high, then even the previously unprofitable wells are brought back into the production.

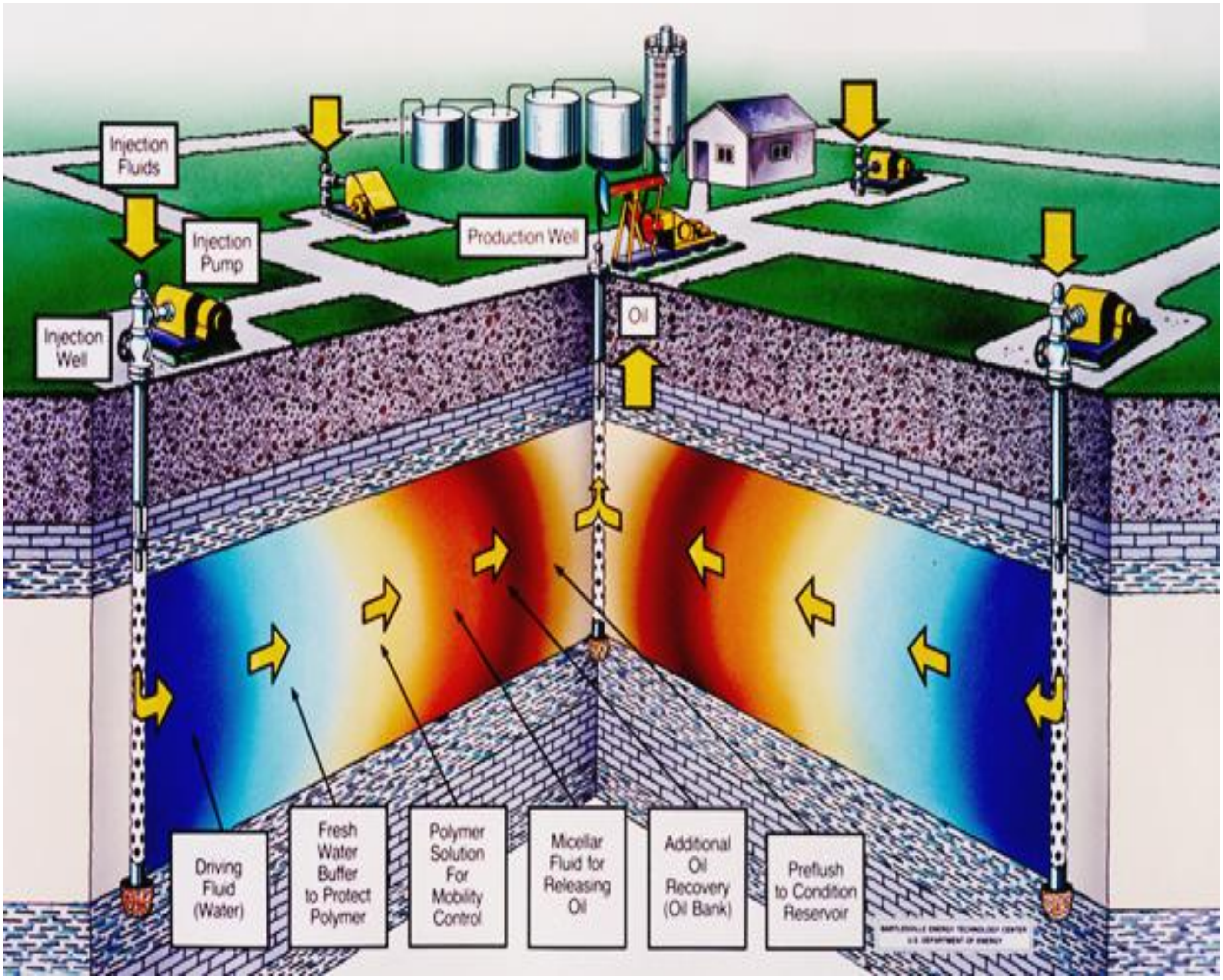


Figure-16 Schematic for chemical enhanced recovery process [netl.doe.gov]

4.1. ALKALINE FLOODING

Alkaline flooding also known as caustic flooding appears to be the most attractive among the various non thermal processes. Alkaline flooding (caustic flooding) involves alkaline chemicals, such as sodium hydroxide, sodium carbonate, or sodium orthosilicate, are injected during water flooding or during polymer flooding operations. These Alkaline reagents are quite cheap and abundant. The alkaline reagents react with the surface active materials present in the crude oil and form the in-situ formation of the surfactant soap species. The adsorption of these generated surfactants at the oil/water/sand interfaces reduces the interfacial tension and raises the PH of the injected flood water; as a result the residual oil trapped in the fine pores of the reservoir sand is mobilized.

To understand this process let us consider the state of these reservoirs at the time of injection of chemicals. In heavy oil reservoirs, the un-recovered oil at the end of the water flooding was bypassed due to the adverse mobility ratio between oil and water, this oil is capable of flow but it depends upon the applied pressure gradients and permeability of the rock. Bryan et al., postulated that a simple reduction in oil-water interfacial tension as proposed in the mechanism for enhanced oil recovery of the conventional oil, cannot be effective in displacing oil. He believes that the injected chemicals will be the better choice for improving the mobility ratio between the oil and water, thus giving more stable displacement of oil to the production wells.

Campbell (1982) asserted that, of the several alkaline reagents available only sodium hydroxide and sodium silicates have sufficient alkalinity to react quickly with the natural acids present in crude oils. Since lower-pH alkalis are not generally appropriate for the recovery of highly acidic heavy oils, however it should be noted that Jensen and Radke (1992) have demonstrated that sodium carbonate tends to propagate through porous rocks at significantly higher rates than strong alkalis.

Campbell (1982), Jensen and Radke (1992) did not throw much light on the addition of silicates. The addition of silicates is an enhancement to alkaline flooding. The silicates play two major functions:

1. **Act as a buffer:** This means it maintains a constant high pH level to produce a minimum interfacial tension.
2. **Improves surfactant efficiency:** this is done by the removal of hardness ions from reservoir brines, thus reducing adsorption of surfactants on rock surfaces.

This method is not recommended for the carbonate reservoirs; the reason is that the abundance of calcium ions reacts with the alkaline chemical to produce calcium hydroxide, which is basically a precipitate that may damage the formation.

4.2. CARBON DIOXIDE FLOODING

Carbon dioxide is injected into an oil reservoir in order to increase output when extracting oil. This process can be understood by considering figure-17 which depicts an existing well that has been produced before and has been designated suitable for carbon dioxide flooding; the first action is to restore the pressure within the reservoir to one suitable for production. This is done by injecting water and shutting off the production well. The water serves to increase the sweep efficiency and to minimize the amount of carbon dioxide required for the flood. Then the next step is the injection of carbon dioxide into the same injection well used to restore the pressure; when the carbon dioxide comes in contact with the oil, it creates a miscible zone that can be moved more easily to the production well. As reservoir fluids are produced through production wells, the carbon dioxide reverts to a gaseous state, which provides the "gas lift" similar to the original natural reservoir pressure.

Heller and Taber (1982) nominated Carbon dioxide flooding as the most commonly used method to recover oil from reservoirs in which the initial pressure has been depleted through primary production and possibly water flooding.

Carbon dioxide flooding increases the productivity by:

1. The reduction of viscosity.
2. Swelling of oil.
3. Vaporization of oil.
4. Reduction of interfacial tension.

These mechanisms depend on whether the Co_2 displacement is miscible or immiscible. If we take miscible carbon dioxide process than the vaporization of crude oil, development of miscibility, and reduction of interfacial tension are very important and if we consider the immiscible carbon dioxide displacement than reduction of the crude oil viscosity and swelling of the oil are dominant factors.

According to Mungan (1992) two types of reservoirs can be particularly suited for Co_2 flooding, which are:

1. Carbonate formations which may not have high enough injectivity to make water flooding successful.
2. Reservoirs which contain under saturated crude oils.

Approximately 95% of heavy oil formations present in Saskatchewan are less than 10m thick, and most of them have underlying water and sand. These formations are not ideal for thermal methods because it is uneconomical to use these methods due to excessive vertical heat loss and steam scavenging by the bottom water. This provides the motivation for seeking an alternative to thermal recovery techniques for thin, moderately heavy oils.

In past few years the main problems encountered in carbon dioxide flooding process are corrosion and foaming problems. The corrosion problem is due to the formation of carbonic acid. Foaming problems are due to the nature of the crude oil, low gravity, and high viscosity, plus the carbon dioxide trapped in the oil.

The corrosion problem has been minimized by using some of the following procedures

1. Production well flow lines constructed of fiberglass.
2. Injection well tubing string internally coated with plastic.
3. Batch treatment of injection wells with scale and corrosion inhibitors.
4. Transportation of carbon dioxide and water in the separate line of injector.

Farouq Ali (1999) suggests that continuous addition of defoamer at the tank batteries can help to eliminate the foaming problem. Heat and chemicals are also required in a few cases for the separation of oil and water.

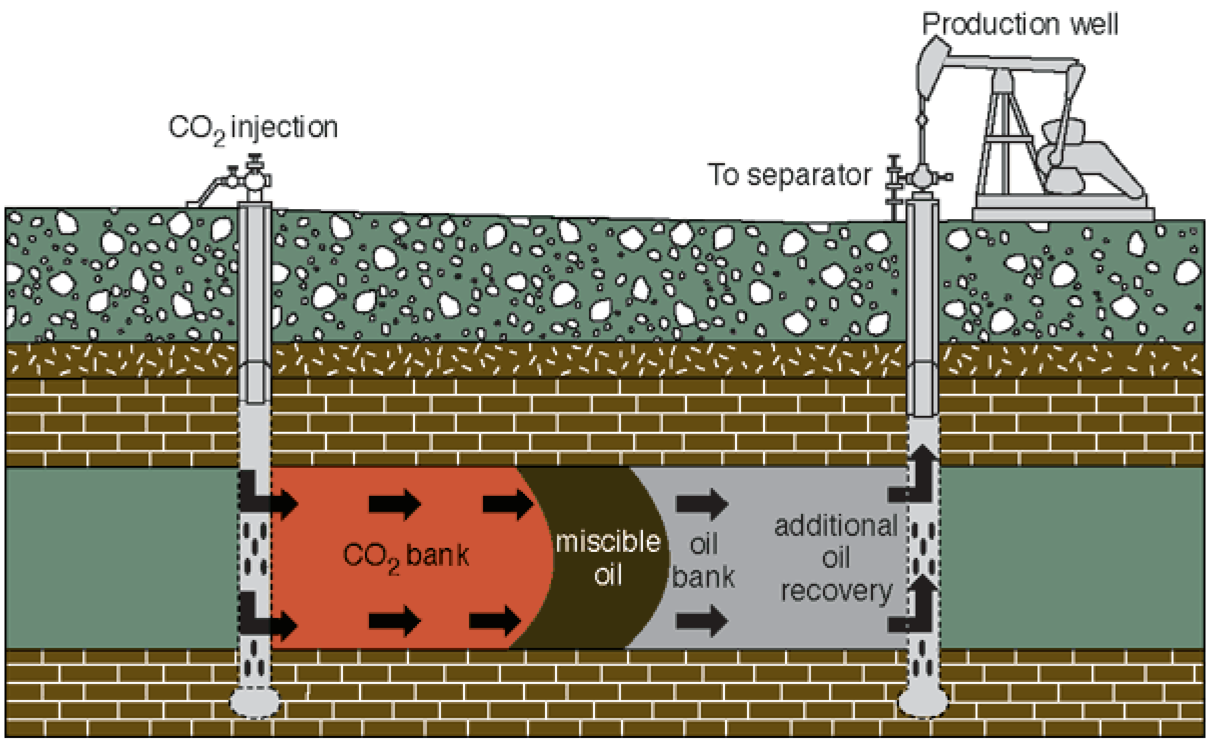


Figure-17 Carbon dioxide flooding [Buchanan and Timothy, 2011]

4.3. CYCLIC CARBON DIOXIDE STIMULATION

This method bears a resemblance to the cyclic steam process (which will be discussed later). First carbon dioxide is injected into the reservoir, than the well is shut in for a certain amount of time (providing for a soak period), and the well is opened after a certain period, allowing the oil to produce. This is a single well process. Just like the carbon dioxide injection process, the dissolving of the carbon dioxide in the oil reduces the viscosity and causes it to swell, allowing the oil to flow more easily towards the well. Carbon dioxide is injected by high pressure for heavy oil reservoirs. There are two types of carbon dioxide-enhanced oil recovery processes which are miscible and immiscible.

4.3.1. Miscible carbon dioxide-enhanced oil recovery process

The miscible carbon dioxide-enhanced oil recovery is a multiple contact process, involving the injected carbon dioxide and the reservoir oil. In this process carbon dioxide vaporizes the lighter oil fraction during the injection phases and then it condenses into the reservoir oil phase. This leads to two reservoir fluids that become miscible and as a result we get more mobile fluid with low viscosity and low interfacial tension. The primary objective of miscible carbon dioxide-enhanced oil recovery is to remobilize and dramatically reduce the after-water flooding residual oil saturation in the reservoir's pore space.

4.3.2. Immiscible carbon dioxide-enhanced oil recovery process

When insufficient reservoir pressure is available or the reservoir's oil composition is less favorable (heavier), the injected carbon dioxide will not become miscible with the reservoir's oil. Then, another oil displacement mechanism, immiscible carbon dioxide flooding, occurs. The immiscible carbon dioxide flooding process has considerable potential for the recovery of moderately viscous oils, which are unsuited for the application of thermal recovery techniques.

The main mechanisms involved in immiscible carbon dioxide flooding are:

1. Oil phase swelling which is as a result of oil saturation with carbon dioxide.
2. Viscosity reduction of the swollen oil and carbon dioxide mixture.

Farouq Ali (1989) suggests that the target reservoirs for the application of immiscible carbon dioxide are those with oils that cannot achieve miscibility with carbon dioxide and also with those reservoirs that are either very thin or deep for economic and practical application of thermal methods.

CHAPTER 5 THERMAL RECOVERY METHODS

Generally there are two thermal methods of recovering heavy oil:

1. The process in which heat is injected into the reservoir.
2. The process in which heat is generated within the reservoir itself.

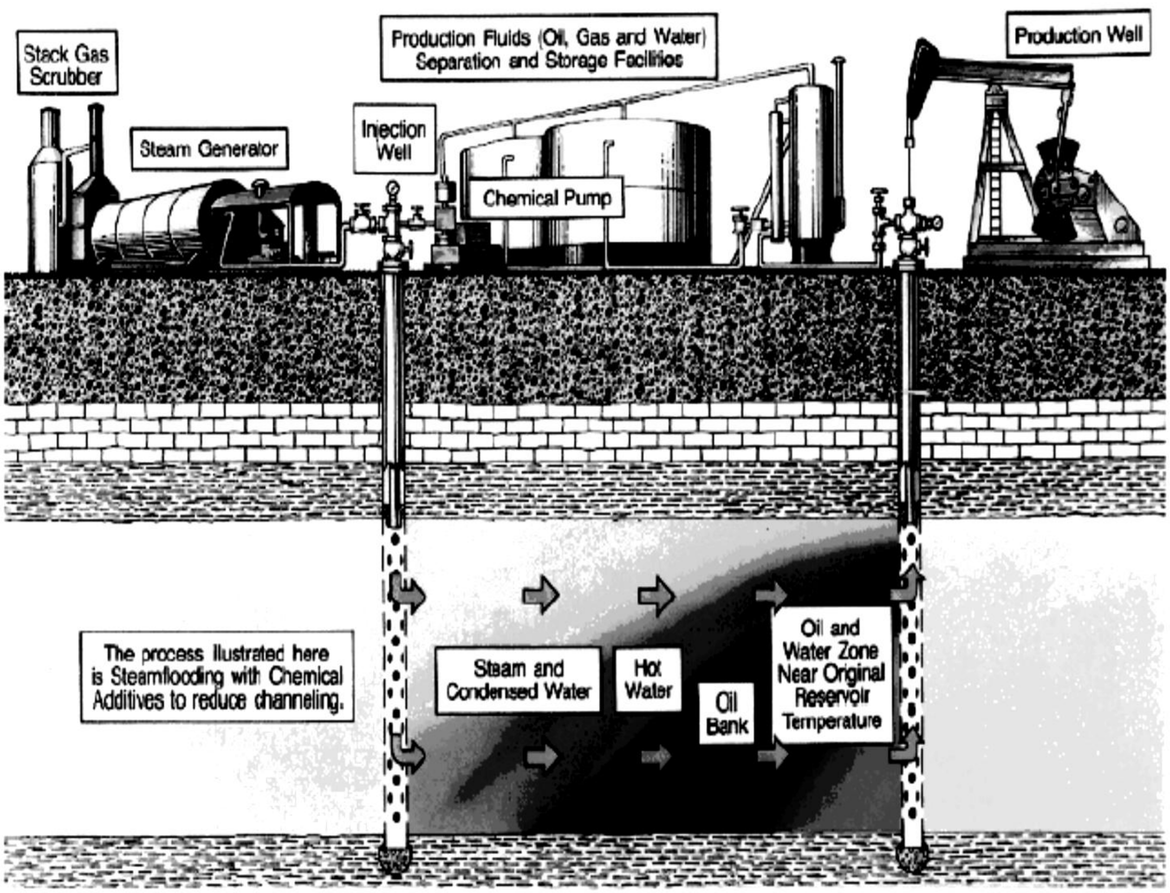


Figure-18 Oil recovery by thermal methods. [Thomas, 2008]

Steam based process were used before the advancements in the field that introduced new processes such as in situ combustion or fire flooding. Thermal recovery process reduces the viscosity by means of heat and also provides the force to increase the flow rates of the oil to the production well that's why thermal processes are also classified as thermal drives. In the thermal stimulation techniques, only the reservoir near the production well is heated. Stimulation techniques can also be combined with thermal drives, and in this case the driving forces are both natural and imposed.

As shown in figure-18, the fluid is injected continuously through injection wells to displace oil and obtain production from other wells. The same pressure which maintains the injection of the fluid in the well also increases the driving forces in the reservoir, which increases the flow of crude oil. Driving forces present in the reservoir, such as gravity, solution gas, and natural water drive, affects the improved recovery rates once the flow resistance is reduced and overcome by the driving force. Thermal processes use heat in well bores to increase the production rates for heavy crude oils. The drive process can also be applied to recover the residual oil in energy depleted reservoirs that hold conventional oil.

5.1. HOT FLUID INJECTION

In hot fluid injection methods the preheated fluids are injected into the relatively cold reservoir as shown in figure-19. Injected fluids are usually heated at the surface; although these days well bore heaters which are also known as the down-hole heaters are seeing a wider use. The fluids range from water (both liquid and vapor) and air to others, such as natural gas, carbon dioxide, exhaust gases, and even solvents.

In every hot fluid injection there are heat losses in the well bore from the injection wellbore to the over burden formations as a result of poor insulation of the injected wells and low injected rates. When the heat approaches the formation there is a temperature difference between the well head and the formation as a result of heat loss. In case of condensable fluids such as steam, the heat losses cause the condensation of steam, which then turns into hot water, and oil comes in contact with the hot water rather than steam. To overcome this issue surface lines are insulated.

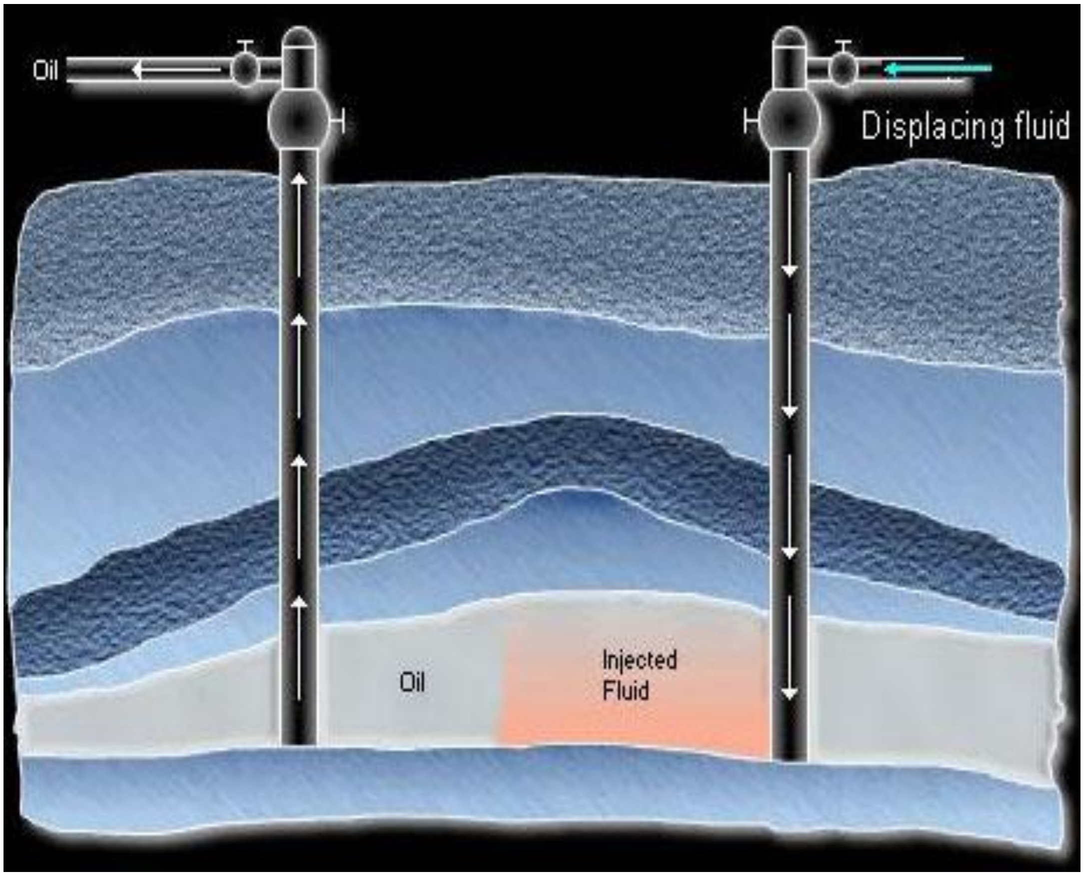


Figure-19 Hot Fluid Injection [tandem-terminal.ru]

5.2. HOT WATER DRIVE

Hot Water drive involves the flow of only two phases, water and oil, in which oil is displaced by water. In this process the leading edge of the water comes to the initial reservoir temperature as it loses heat very quickly and increases the mobility of the fluids in the heated zone. This results in better displacement efficiency from the heated zone and would improve the ultimate recovery. Basically the concept is that the thermal expansion of oil facilitates the displacement of oil, because of the pervasive presence of water in all petroleum reservoirs, the displacement by water must occur to some extent in all thermal recovery process. Typically, in hot-water flooding, the water is filtered, treated to control corrosion and scale, heated, and if necessary, treated to minimize the swelling of clays in the reservoir.

In order to make it cost effective, the choice of fluid can be made according to the availability of fluid and its production response of the crude oil. For example, seawater may be injected in the undersea reservoir, which can save the cost of delivery of water to the reservoir. Also the mineralogy of the reservoir should be considered; for example, steam or hot water should not be injected without first considering their effects on the reservoirs containing swelling clays.

5.3. STEAM BASED METHODS

The concept behind the steam-based processes is to reduce the viscosity so that the heavy oil can flow to the production well. In most instances the injection pressure must exceed the formation pressure in order to force the steam into the reservoir and into contact with the oil. When sufficient heating is achieved, the wells are closed and left for a certain period, which is referred to as the soak period. There is no chemical change in the constituents of oil, but there will be favorable changes in the composition, which will result the recovery of the lighter fractions, and the heavier materials will remain in the reservoir.

As the steam condenses, the steam distilled components also condense and form a solvent front that will assist in displacing heavy oil as a mixture of solvent and oil towards the production well. These effects will help to improve the displacement efficiency. Whether or not steam distillation occurs and the role it plays in oil recovery depends on the character of the heavy oil as well as the down-hole conditions. For example, most of the times when dealing with heavy oil, the steam distilled material is composed of aromatic and naphthenic constituents, which are excellent solvents for oil. But when the constituents are predominantly paraffin character result in the deposition of asphaltic material ahead of the steam front, and this deposition will cause the blockade in the reservoir flow channels, which will restrict the oil flow to the production well. Luckily paraffin character is not often found in heavy oil reservoirs.

5.4. STEAM DRIVE INJECTION

High quality steam is injected in the production well. After pumping down the pressurized steam for weeks and sometimes months, the process is halted, usually for several weeks, which allows the heavy oil to separate from the reservoir sand, and then it is artificially lifted. Normally steam travels on the top of the sand and gravity helps the oil to resaturate the steam zone, from where it is displaced towards the wells.

Two steps are involved in the steam drive injection process:

1. Direct steam stimulation: steam stimulation of production wells.
2. Indirect steam stimulation: Steam injection from other wells. When there is some natural reservoir energy, steam stimulation normally precedes steam drive.

A successful steam drive project should have the following characteristics; these parameters have been noted on the basis of success with several heavy oil reservoirs.

- **Porosity of the reservoir rock** should be at least 20%.
- **Permeability** should be at least 100 millidarcies.
- **Heavy oil saturation** should be at least 40%.
- **Reservoir oil content** should be at least 800 bbl per acre-foot.
- **Depth of the reservoir** should be less than 3000 feet, and the thickness should be at least 30 feet.

5.4.1. Limitations

Two problems inherent in the steam drive process which are steam over ride and reservoir plugging. Override is because of the difference in the density of the hot fluid and cold fluid. These problems can be partially mitigated by rapid injection of steam at the bottom or below the target interval through a high-permeability water zone or fracture which will raise the temperature of the entire reservoir by conduction and convection. This will enhance the injection of steam in the target interval therefore there will be no migration at the top of the affected interval.

5.5. CYCLIC STEAM INJECTION

Cyclic steam injection is the process in which steam is injected in variable intervals followed by a period of production. This is the alternating injection of steam and oil production with condensed steam. Same well is used for production and injection.

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

Figure-20 shows three phases in cyclic steam stimulation. First, high-temperature, high-pressure steam is injected for up to one month. Second, the formation is allowed to soak for one or two weeks to allow the heat to diffuse and lower the heavy oil viscosity. Third, heavy oil is pumped out of the well until production falls to uneconomical rates. Then the cycle is repeated, until production can no longer be recovered. Artificial lift is required to bring the heavy oil to surface.
The steam heats the reservoir in the vicinity of the well bore, and thus causes a reduction in oil viscosity where the converging oil stream experiences the highest resistance to flow. This effectively increases the oil production rate by making warmed heavy oil back into the well. However, the steam injection contributes little to the physical mechanisms that move the oil to the well. Therefore reservoirs with little or no primary energy are not suitable candidates for steam injection.

Cyclic steam injection is suitable for the reservoirs with the following characteristics

- **Depth:** the minimum depth for applying cyclic steam stimulation is on the order of 1,000 feet.
- **Porosity:** should be no less than 30%
- **Permeability:** good horizontal permeability (at least 1 Darcy or greater) is important for production.
- **Thick pay zone:** This process is economical on reservoirs that contain pay zones of 10 meters and above.

5.5.1. Limitations

The major limitation of cyclic steam injection is that it leaves considerable amounts of oil in the reservoir that can only be recovered by drive processes and it is observed that less than 30% (usually less than 20%) of the initial oil in place can be recovered. One more limitation of this process is that it is preferred production on heavy oil reservoirs that can contain high-pressure steam without fracturing the overburden.

5.5.2. Field Projects

Cyclic steam stimulation and steam floods are used in California, western Canada, Indonesia, Oman, and China. California's Kern River production rose from less than 20,000 barrels per day in the late 1950s before cyclic steam stimulation to over 120,000 barrels per day by 1980 after the introduction of cyclic steam stimulation. The Duri field in Indonesia is the world's largest steam flood and produces 230,000 barrels per day.

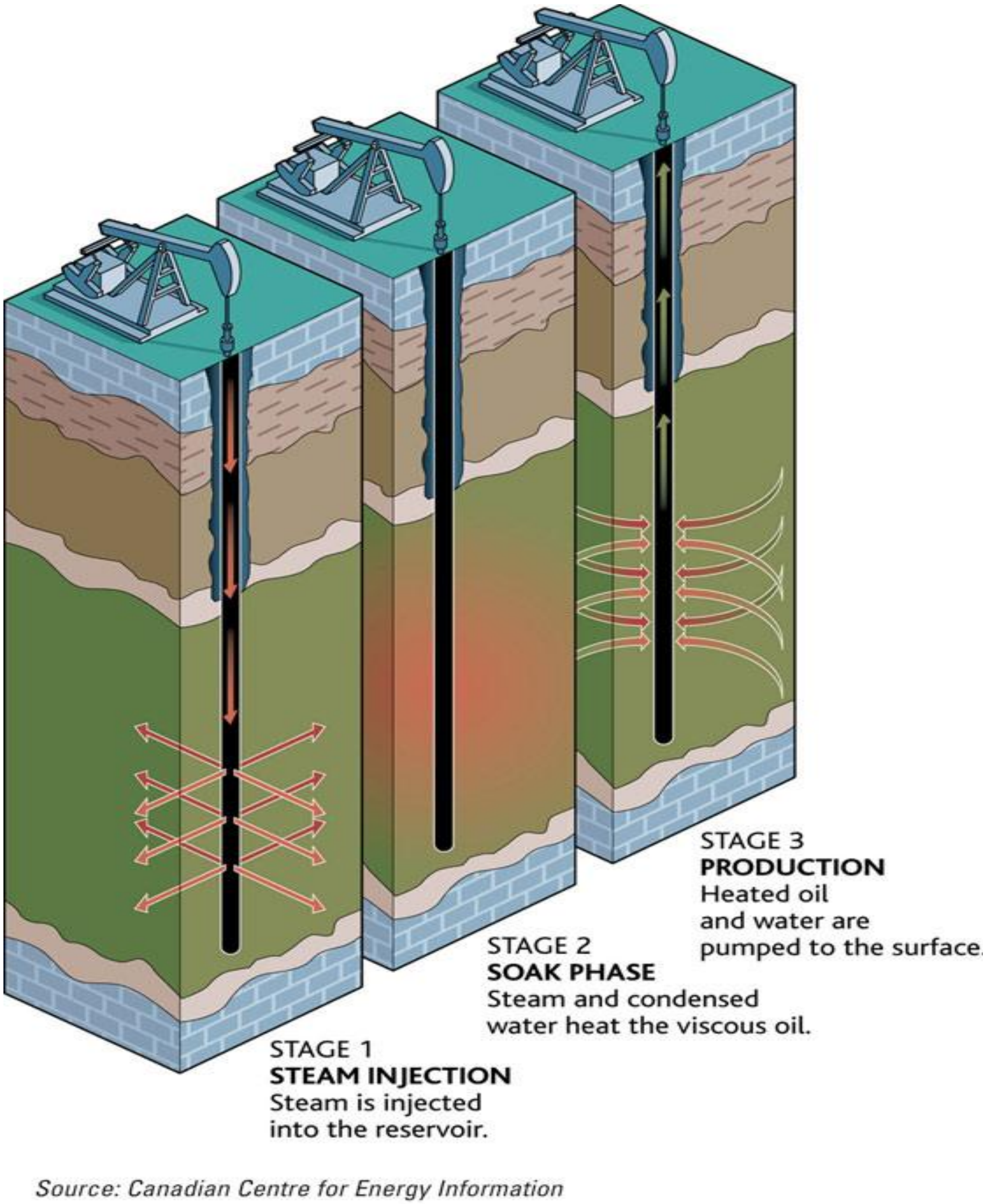


Figure-20 Stages of cyclic steam injection

5.5.3. Technical Challenges

Technical challenges are of the economic side and are primarily related to cost of the steam, this steam can be used in place of natural gas. This process can be made more economical by generating and selling electricity and using the waste heat for cogeneration (as shown in figure-21). Enhanced oil recovery projects can be more efficient by installing combustion turbines, coupled with heat recovery steam generators, and at the same time it provides them the opportunity to meet the fluctuations of the oil and electricity markets. This is mostly based on the simultaneous production of heat for reservoir injection and electricity, or on the generation of mechanical power to be converted into electrical energy and heat for steam production.

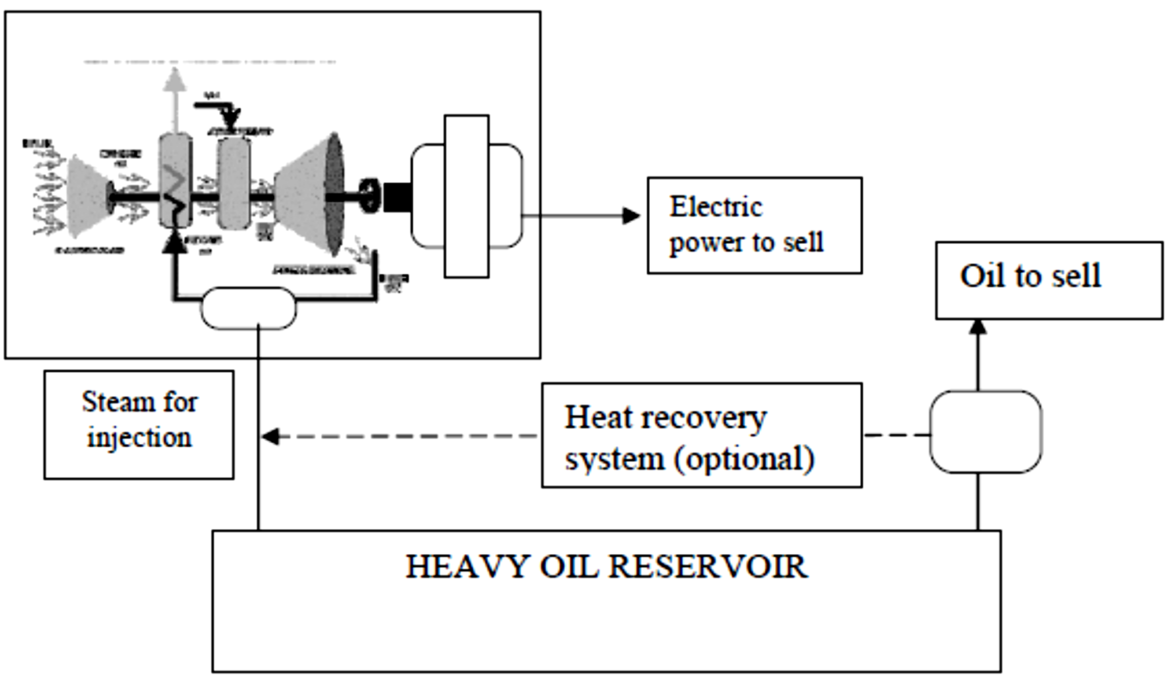


Figure-21 Existing EOR methods with cogeneration of steam and electricity [Teodoriu et al., 2004]

Monitoring and controlling the steam front could also help in controlling the cost and steam can be redirected to zones where the heavy oil has not been produced, and shut off from the zones that have been successfully swept and directed toward un-swept regions.

A question of an unconventional nature is: How much, how often, and when must steam be injected to obtain optimum project performance? To answer this question one must know the affect on various wells as they are supplied with the steam from the available steam capacity. To be able to decide where the steam can be injected most profitably at any moment Teodoriu et al., (2004) believe that one must know how steam injection would affect the well.

5.6. COMPARISONS

5.6.1. Comparison between Hot water drives and steam drives

It is observed that steam creates high temperature zones, because it can lose heat by condensation without changing its temperature which is not found in hot water drive. This condensed steam increases the sweep efficiency and the net effect is greater volume of recovery from steam drives than the water drive.

The greater stability of steam drives gives it significant command over hot water drive. Hot water drive can be used in heavy-oil reservoirs in the lower viscosity range, up to a few hundred centipoises, because it is expensive to produce steam. Water drive is competitive to steam drive in high pressure reservoirs or reservoirs with large well distance. The reason is that in those kinds of reservoirs heat affects larger areas at lower temperatures.

5.6.2. Comparison between Cyclic Steam Injection and Steam Drives

The increasing use of cyclic steam injection for increasing the heavy-oil potential in undepleted reservoirs and its consequent rapid development over steam drive is due to the economic stability of this process. One more advantage of cyclic steam injection is that in a subsequent drive steam injection pressure can be lower which can stop the rapid depletion of reservoir pressure.

In reservoirs containing heavy crude oil, the high resistance between the wells is sufficient enough to make steam injection rates limited, which is why it is not possible to use steam drive. Cyclic steam injection reduces this resistance and connects heating zones of adjacent wells.

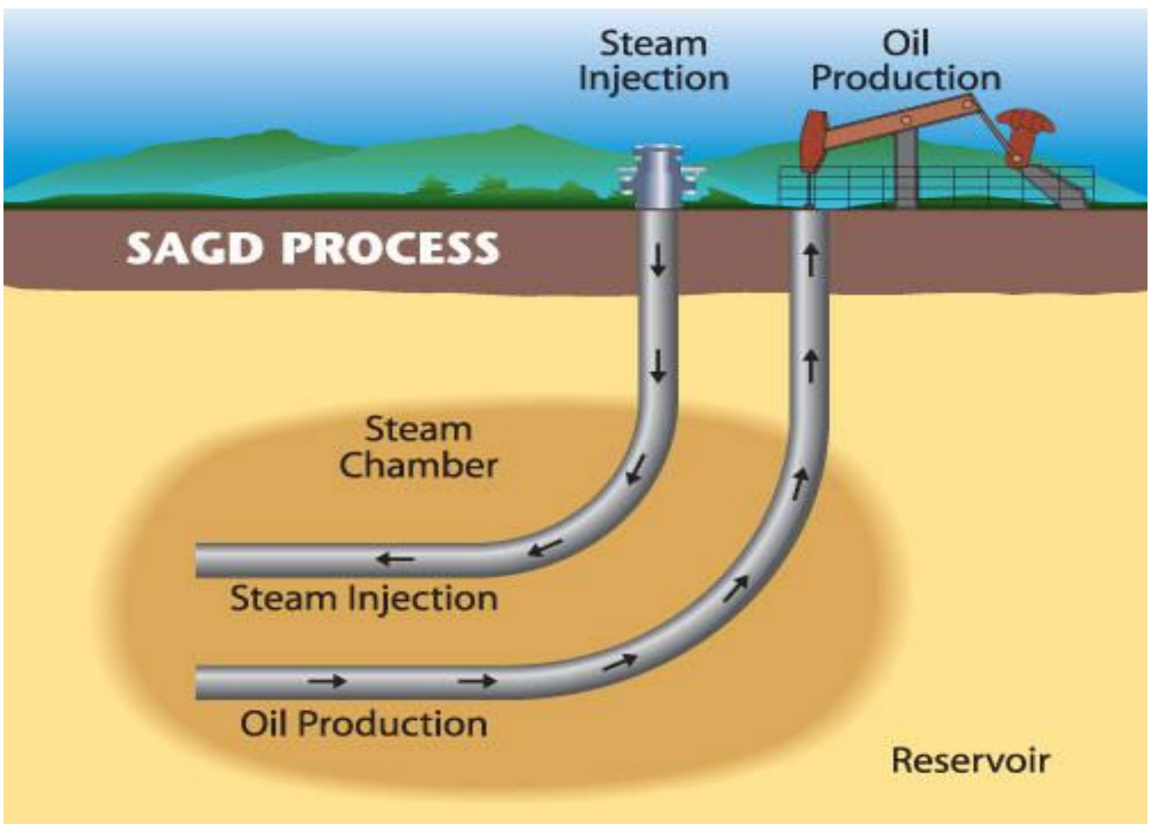
It is true that cyclic steam injection is used as a precursor to steam drive technology. Ultimate recoveries from steam drives are generally much larger than those from cyclic steam injection. Thus, cyclic steam injection followed by a steam drive is an attractive combination; crude production is accelerated quickly, and the ultimate recovery is quite high.

5.7. STEAM-ASSISTED GRAVITY DRAINAGE (SAGD)

This method involves drilling of two parallel horizontal wells (shown in figure-22), one above the other, along the reservoir itself. Hot steam is introduced from the top well which reduces the viscosity of the heavy oil (like all other thermal methods). The reduction in viscosity of the heavy oil separates it from the sand and it is drained into the lower well by means of gravity. The key to this method is the two parallel and horizontal wells, and this has only become possible due to the directional drilling technology.

The heat of the steam reduces the viscosity of the heavy oil and separates it from the sand. It is drained into the lower well by means of gravity. Even though the injection and the production wells can be close (5-7m), the mechanism causes the steam saturated zone, known as the steam chamber, to rise on the top of the reservoir, expand gradually sideways, and eventually allow the drainage. The distance between the pair of horizontal wells vertically separated by each other is 15-20 feet. These wells are drilled at the bottom of a thick unconsolidated sand stone reservoir. The injected steam reduces the oil viscosity to values as low as 1 -10 cP, depending upon the temperatures and the initial conditions and develops a steam chamber that grows vertically and laterally. The steam and gases rise, the lower well receives oil and condensates due to the density difference. The products are methane, carbon dioxide, and some traces of hydrogen sulfide. The non condensable gases act as a partial insulation blanket by filling up the void space, which helps to reduce the vertical heat losses. Injection pressures are much lower than the fracture gradient, which reduces the chances of breaking into thief zone.

The SAGD process, like all gravity driven processes, is extremely stable because the process zone progresses by means of gravity segregation, and there are no pressure driven instabilities such as conning, fracturing, or channeling. It is vital to maintain a volume balance; it means that each unit volume injected is replaced by each unit volume withdrawn or reduced. If bottom-water influx develops, this indicates that the pressure in the water is higher than the pressure in the steam chamber, so this pressure should be balanced. It is obvious that the pressure in the water zone cannot be reduced, so the pressure in the steam chamber and production well must be increased. This increase in pressure is achieved by increasing the operating pressure of the steam chamber through the injection rate of steam or by reducing the production rate from the lower well.



Source: Canadian Centre for Energy Information

Figure-22 SAGD Process (fluid movement in horizontal wells).

SAGD is also successful on shale streaks and similar horizontal barriers (as thick as 3-6 feet) as they restrict the vertical flow. This occurs because of heating of the rock, and the differential thermal expansion would cause the shale to be placed under a tensile stress, which creates vertical fractures and serves as conduits for steam (up) and liquids (down). As high temperatures hit the shale, the water content absorbed in the clay is liberated, and dehydration causes the shale barriers to shrink. This causes the lateral stress (fracture gradient) drops until the pore pressure exceeds the lateral stress, which causes the vertical fractures to open.

The combined processes of gravity segregation and shale thermal fracturing make SAGD so efficient that recovery ratios of 60% to 70% are probably achievable, even in cases where there are many thin shale streaks. The method is claimed to significantly improve heavy oil recovery by between 50% and 60% of the original oil in place (OOIP) and is therefore more efficient than most other thermal recovery methods.

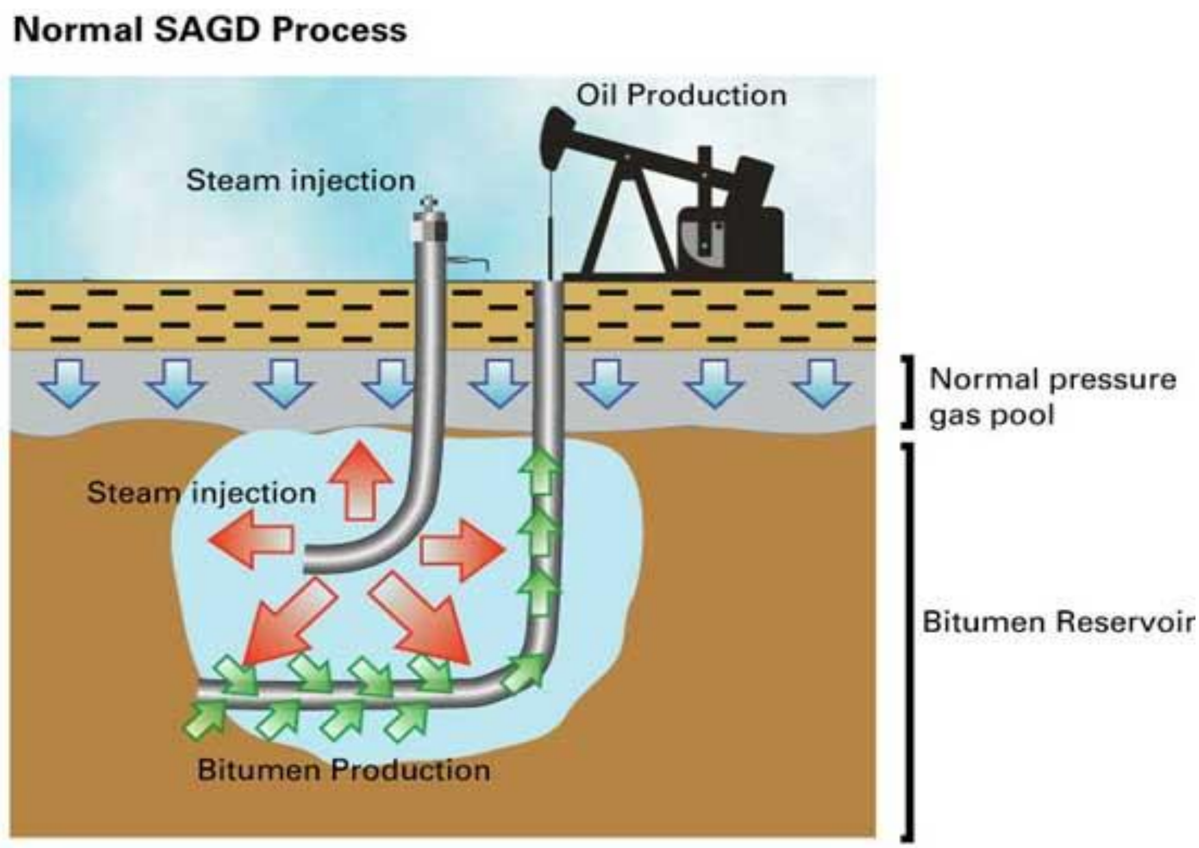


Figure-23 SAGD Process [ERCB]

The cost of heat (for the production of steam) is a major economic constraint on all thermal processes. SAGD operates on low pressures and is thermally more efficient than the cyclic steam stimulation. SAGD is not suitable for clear water formations. It performs best in clean, continuous sands, and it requires continuous vertical permeability. The reason of this process not being functional in clear water is because the Clearwater formation is neither as permeable nor as vertically continuous.

5.8. IN-SITU COMBUSTION

In Situ combustion was the center of attention in 1950's when many papers were published on this particular method and until the 1960's most of the projects of thermal oil recovery were connected with this process. In-Situ combustion applies on the reservoirs that contain low gravity oil, which is heated with the help of air injection and the burning part of the crude oil. The oil is then driven out of the reservoir with the help of steam, hot water or gas drive, as it becomes less viscous. Either dry or moist air can be injected. The fire propagates from the air injection well to the producing well, moving oil and the combustion gases to the front. The coke left behind the displaced oil works as a fuel. The temperature reaches hundreds of degrees which is enough to crack heavy oil into low boiling products, below is the summary of different reactants and their products formed as a result of cracking of asphaltenes (Figure-24). The displacement of oil is the result of the combination of hot water, steam and gas drive, vaporization, and light hydrocarbons.

Wu and Fulton (1971) found through different experiments that, as the temperature in the volume element exceeds about 345°C (650°F), the oil will more than likely undergo thermal cracking to form a volatile fraction and a low-volatility, coke-like residue. The volatile products are carried in the gas stream, while the coke-like residue is burned as fuel in the combustion zone. The heat generated at the combustion zone is transported ahead of the front by means of conduction through the formation matrix and by convection through vapor liquids.

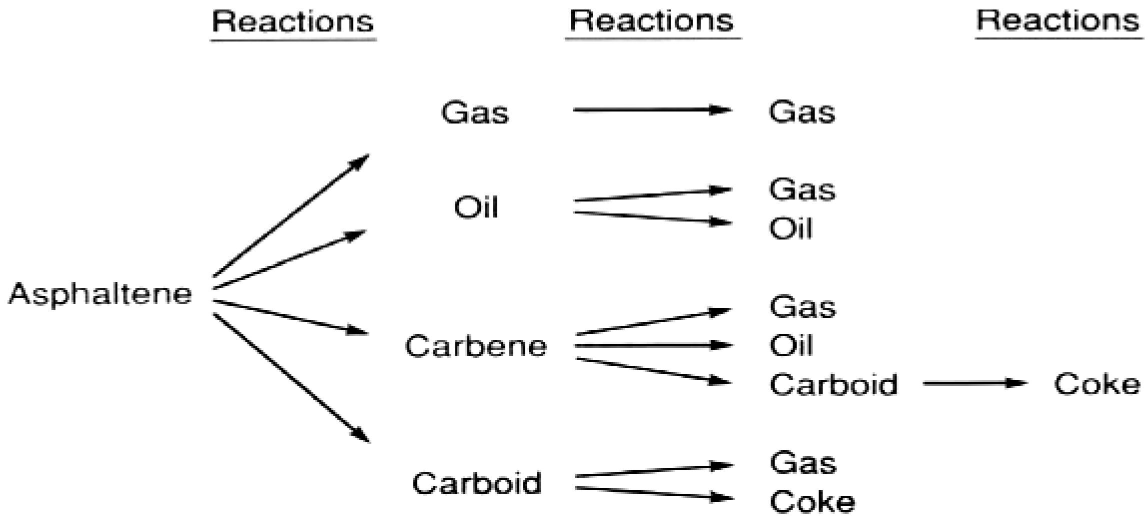


Figure-24 Multi-Level cracking using the asphaltene constituent as an example [Thomas, 2008]

Alexander et al., (1962) define the parameters which determine the design of the in situ combustion process (in addition to the operating cost) which are as follows:

1. The fuel concentration per unit reservoir volume burned.
2. The composition of the fuel.
3. The amount of air required to burn the fuel.
4. The volume of reservoir swept by the combustion zone.
5. The required air injection rates and pressures.
6. The oil production rate.

The success of the process depends upon the parameters described by Alexander et al., (1962) which can be measured by the following four factors:

1. The quantity of oil that initially resides in the rock to be burned.
2. The quantity of air required to burn the portion of the oil that fuels the process.
3. The distance to which vigorous combustion can be sustained against heat losses.
4. The mobility of the air or combustion product gases.

A major difficulty encountered in operating in situ combustion processes addressed by Okazawa et al., is low temperature oxidation (LTO), it involves the oxygen addition reactions that occur at temperatures lower than 300 °C. The problem is due to the formation of oxidized hydrocarbons that have an increased polarity. These hydrocarbons are the byproduct of these reactions. The increases polarity makes them more viscous.

The application of thermal energy to increase heavy oil recovery has become more popular as conventional reserves decline. Steam injection accounts for the majority of the thermal recovery projects currently in operation; however, in situ combustion offers many theoretical advantages if the operational characteristics of the process are incorporated in the design and operation of the field project. The in situ combustion process has the potential of partial upgrading of the oil in the reservoir, which restrains the undesirable constituents of oil from moving along with the oil. Also there is no need to generate energy on the surface.

There are several variants of the in situ combustion process, which are:

1. Forward Dry in-situ combustion
2. Wet and partially quenched combustion, also known by the acronym COFCAW (combination of forward combustion and water flooding).

5.9. FORWARD DRY IN-SITU COMBUSTION

When air is injected alone Kuhn and Koch (1953) termed that as dry underground combustion, in situ combustion, or fire flooding. This is the most common combustion process. The crude is ignited by the injection of air or any suitable oxidizing gas into the formation. This results in a combustion front which propagates through the reservoir, reducing the oil viscosity and increasing the oil recovery. The combustion front can move more rapidly and heat reaches by conduction and convection in a reservoir, the convective heat wave velocity for the case of air injection is about one quarter that of the combustion front.

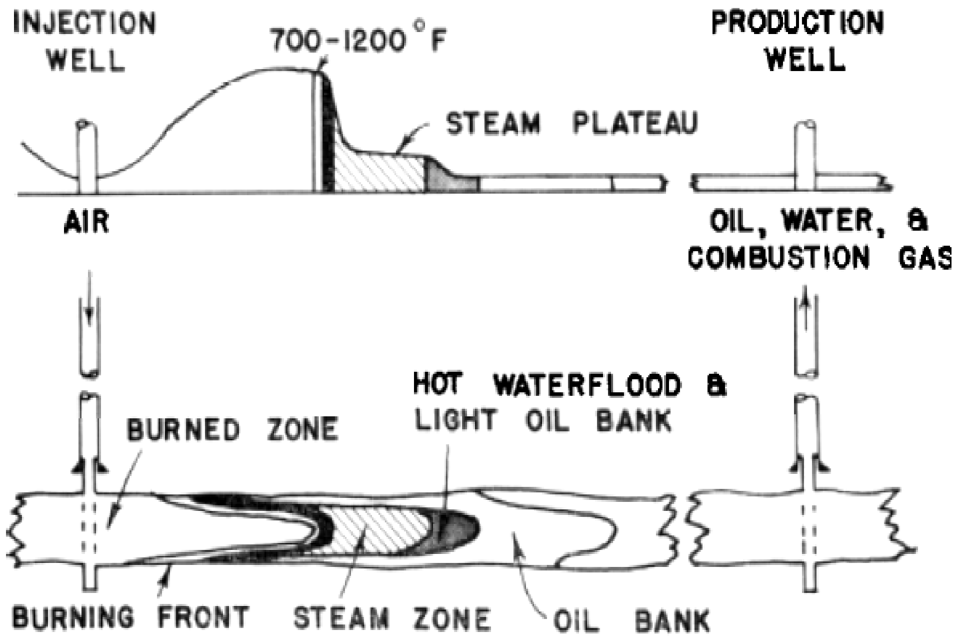


Figure-25 Schematic diagram of in situ combustion oil recovery [McNiel and Moss, 1958]

Figure-25 illustrates the process, first air or any suitable oxidizing gas is injected into the formation. The oil is ignited at the injection well, and the burning front moves in the direction of gas flow. After the burning front has moved a significant distance towards the producing wells, there is a burned region from the injection sand face to the burning front. This region will essentially dry, and the increase in temperature is due to the injection of air at the sand face to a maximum temperature at the burning front. Air injection is continued which recuperates heat from the burned sand, which moves towards the burning front. The burning front movement is the result of complete combustion of all fuel. Immediately ahead of the burning front there is a sudden drop in temperature through evaporation and cracking zone. This is the zone where evaporation of all light components of crude oil and water takes place, leaving the fuel residue. Immediately ahead of the evaporation zone is a zone of condensation which is also called as the 'steam plateau'. Ahead of the condensation zone, temperature drops gradually to initial formation temperature. Usually, a 'fresh' water and 'light' oil bank can be identified immediately ahead of the condensing region. According to Henry and Ramey, the 'fresh' water bank is the result of formation of water by combustion of the hydrogen in the hydrocarbon fuel. The 'light' oil bank results because of condensation of light ends from the crude oil, the heavy ends being consumed as fuel. As a result of the combustion, the hydrocarbon products released from the combustion zone move into comparatively colder portion of the formation, and the complete burning due to the passage of air into the formation makes it completely cleaned of hydrocarbons. The quantity of fuel that is consumed and the reaction rate within the burning zone is the main factor that describes the efficiency of the process. The maximum oil recovery possible is the difference of the oil in place in the beginning of the operation and the oil that is consumed as the fuel.

5.10. WET COMBUSTION METHOD

The method known as the wet combustion method or partially quenched combustion involves concurrent or alternate injection of air and water. This process was developed when it was felt that the temperatures of burned zones are so high due to the low capacity of air injection that restrains the transfer of significant amount of heat. For this very reason water is used during or after combustion process to help transfer the heat from the burned zone to downstream areas. The addition of water to the injection air stream increases the sensible heat of the injected air stream; the sensible heat of dry air was not enough to recuperate heat, so adding water to the air stream increases the ability of the injection stream to recuperate heat and increases the velocity of the convection wave which normally follows the combustion front. The ratio of air and water is increased to a point where it may match the velocity of the burning front. The result is the maximum combustion front temperature possible in the forward in situ combustion process.

According to Dietz and Weijdema (1963) the purpose of injecting water is to recuperate and transport heat from the burned zone to the downstream of the combustion front, which are the colder regions. They also suggest that this method is suitable for thin reservoirs, where the heat loss to adjacent formation is significant. The additional water injection produces a hot water front which moves with a velocity more than the velocity of the combustion front. This moves heat far ahead of the combustion front, hence aiding both frontal displacements and other beneficial oil displacement mechanisms. If the water-air ratio is increased, the maximum temperature at the burning front declines. The addition of water also creates a larger steam zone

ahead of the combustion zone, which results in the burning of greater volume in the reservoir for a given volume of air injected. This is the result of lower fuel consumption in the combustion zone.
The concept behind all that is increasing the velocity of the burning front by increase in the water-air ratio; it will make the convection wave follow the combustion front. This will result in the maximum combustion water front temperature.

This modified combustion approach has been applied to the Athabasca deposit and 29,000 bbl of upgraded oil were produced from an estimated 90,000 bbl of oil in place.

5.10.1. Technical Challenges

In low permeability reservoirs it may be difficult to inject both air and water simultaneously at the desired rates. In such cases alternate injections of air and water is done. The combustion temperature is controlled by making variations in the air/water ratio; for example, to increase the temperature establish low water/air ratio and to decrease the temperature the reverse is done.

5.10.2. Conclusions on Forward Dry vs Wet Combustion

Dietz (1970) agrees that the wet combustion should be preferred over the dry combustion because he believes that dry combustion will not ever be competitive with other thermal drives. Thus he concludes that there is no need to perform field tests on dry combustion.

Koch (1956) also agrees with Dietz (1970) and postulated that wet combustion would be considered instead of dry combustion where there is ample available water and where water/air injectivity is favorable. Gate and Sklar (1971) mentioned one condition in which wet combustion would not be used; in the case where there is little likelihood that the water would move through the burned zone to recuperate heat effectively, as in gravity-dominated operations.

At the end of the day wet combustion displaces more crude at a given burning front location with the same quantity of fuel.

5.11. REVERSE COMBUSTION

In this process the combustion zone is initiated at a production well. The reverse combustion front travels concurrent to the air injected; i.e., towards the injection well. The burning front moves as all of the oxygen is consumed, because the fuel is in excess. So basically the burning front is moving from the producer to the injection well, while the oil flows towards the production well, through the combustion zone. This method is suitable for the reservoirs containing very viscous crude because in this process no oil bank is formed so the flow resistance decreases with time.

This process has only been proposed as the dry process. The main reason for developing this process is that the forward combustion process is not effective on crude oil which has no mobility. Thus the reverse burning process generates heat near the producing wells that gives the heavy tar some mobility.

Once reaching the ignition sand face, the burning front would change direction as oxygen will not be limited. The burning front would then move towards the producers through the preheated formation as a forward combustion operation.

5.11.1. Technical challenges

One disadvantage of this method according to Dietz and Weijdema (1968) is the likelihood of spontaneous ignition. Due to spontaneous ignition the oxygen will be consumed near the injector, and this will change the process into forward combustion. They also mentioned that historically, reverse combustion has been difficult to maintain because the oxygen is depleted not

far from the injection well. Elkins and Lutton (1974) added, furthermore, sustained air injection into an unheated reservoir generally leads to spontaneous ignition near the injection well.
Another disadvantage of reverse combustion pointed out by Gunn and Krantz, (1980) is the inherent instability of the process, which results in narrow combustion channels being formed and therefore an inefficient burn.

The field tests of this process have been conducted and the results of that were no different than the conclusions by the authors mentioned above. This process was doomed both operationally and economically. First, the normal reactivity of most crude oil will eventually lead to the spontaneous ignition near the sand face and automatically stop the reverse combustion phase. The second reason is that the fuel concentration consumed during the reverse and forward combustion phases was essentially equal, and each of that was equal to the single step of dry forward combustion process, which means that the air costs were around double to those of the forward combustion process.

5.12. THE THAI PROCESS

Toe-to-Heel Air Injection is the process integrated with advanced technology and it has shown potential of high recovery rates of heavy oil. The process is designed in a way that it uses gravity which restricts the drainage of oil in a narrow mobile zone and pushes it into the exposed section of the horizontal production well. The main idea of the toe-to-heel injection process is that a horizontal well is positioned in a line drive in the reservoir, and the air is injected through a horizontal well. The injection well can be vertical but it all depends if the horizontal to vertical permeability allows good distribution of gas into the reservoir. According to M. Greaves and El-Sakr (2001), a horizontal injector will provide a more uniform distribution of air across the inlet reservoir face of the line drive section, which is why it is considered as the baseline well combination. This combination can be extended through a staggered line drive by employing additional horizontal producer wells.

The process begins with preheating of both the wellbores using steam to initiate oil mobility and clear pore space between the injector and the toe of the producing well. During production gas, fuel and water is not required, and the produced water is treated afterwards to usable industry quality. To understand the dynamics of the process let us consider figure-26, first the air is injected through a horizontal well, the injected air migrates preferentially to the combustion front (Combustion front is a part of reservoir where the oil already present is burned, generating the heat to reduce the viscosity of the oil, allowing it to flow by gravity to the horizontal production well) by virtue of the oxygen diffusional gradient established under steady state condition; this is the result of the balance between the oxygen required to burn the fuel (coke) laid down ahead of the combustion front and the removal of the downstream combustion gases. It is achieved because all of the combustion gases and the mobilized fluids drawdown in the exposed section of the horizontal producer well. The combustion front is the moving window which traverses the horizontal production well from the toe to the heel, in other words it sweeps the oil from the toe to the heel of the horizontal producing well. Ahead of the combustion front is the cracking zone (typically around 600°C, 1112°F). In front of the cracking zone there is a 10-15 feet mobile zone where drainage takes place. There is a temperature reduction between 200°C and 350°C right in front of the mobile zone with the corresponding reduction in the rate drainage. The cracking zone and the mobile zone move through the reservoir at about one to three feet per day, depending on the air injection rate. Ahead of the mobile zone is the virgin immobile layer of oil. There is no communication of the gas with this zone which makes the oil flow into the horizontal producer well. This means that THAI process has a built in self-controlling guidance system for fluid flow which gives it an edge over the conventional in-situ recovery process, because the fluid flow is more controllable as compared to the conventional in-situ recovery systems, where fluids can move and penetrate anywhere in the reservoir. Also THAI process has the potential to operate in the reservoirs with lower pressure, higher quality, and deeper than required for the SAGD process. It is estimated that it recovers 80% of the original oil in place and at the same time it partially upgrades the crude oil in situ.

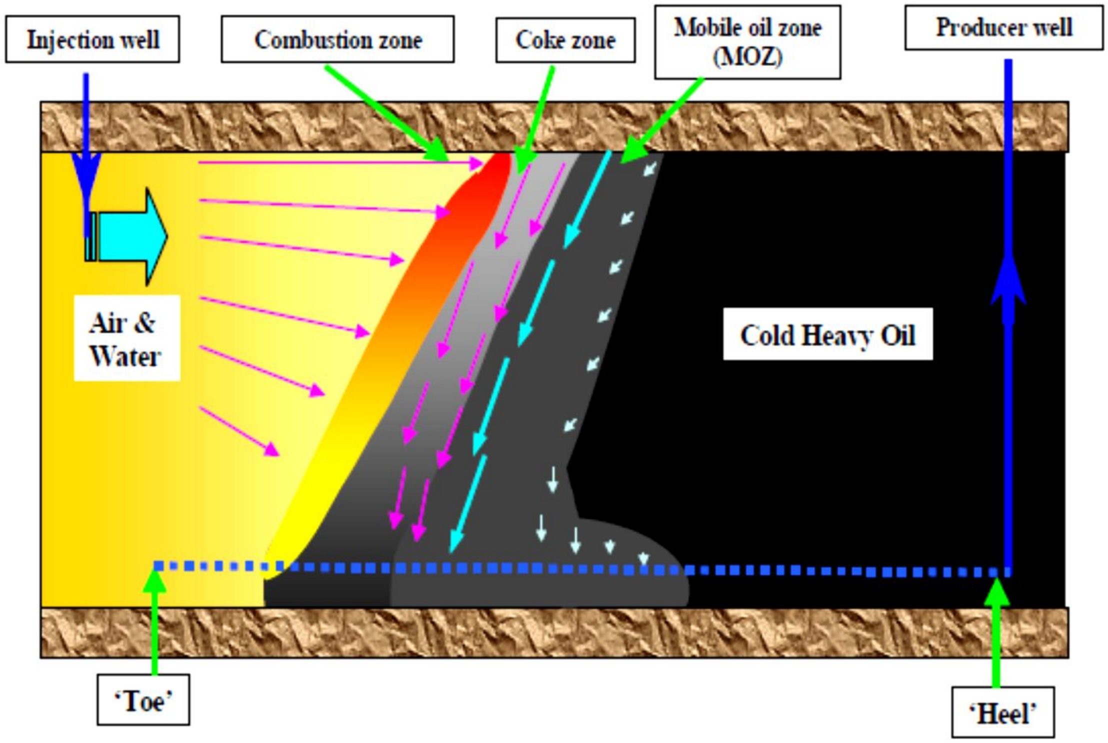


Figure-26 THAI – 'Toe-to-Heel Air Injection' Process [Greaves and Xia, 2005]

The expansion of the heavy oil bitumen production is limited by the lack of advanced upgrading facilities and technology. According to Greaves and Xia (2005) the THAI process achieves substantial upgrading of heavy crude oil directly in the reservoir through thermal cracking and associated reaction transformations. It captures the underground upgrading because the horizontal producer well process operates through a 'short-distance displacement mechanism', similar to that which occurs in the SAGD process.

Greaves and Xia (2005) suggest that this process can be operated on primary production, as a new technology, as a follow-up to existing technologies, or as a co-process where the advantages of high thermal efficiency are required. They believe that this can be achieved by combining clean technology design with concentration on areas such as the energy required for oil mobilization, recovery, and thermal upgrading in the reservoir.

The laboratory tests agree with what is mentioned by Greaves and Xia (2005). It is a benefit of THAI process that it performs in situ upgrading through thermal cracking of the heavy oil. Several tests being conducted on field and as well as in laboratories and it was observed that the upgrading by 10°API is achievable. On this basis, 10° API oil could be expected to yield an 18° to 20° API oil at the surface. This is a very desirable feature of any recovery process since every increase of 1° API can mean refinery savings of several dollars per barrel.

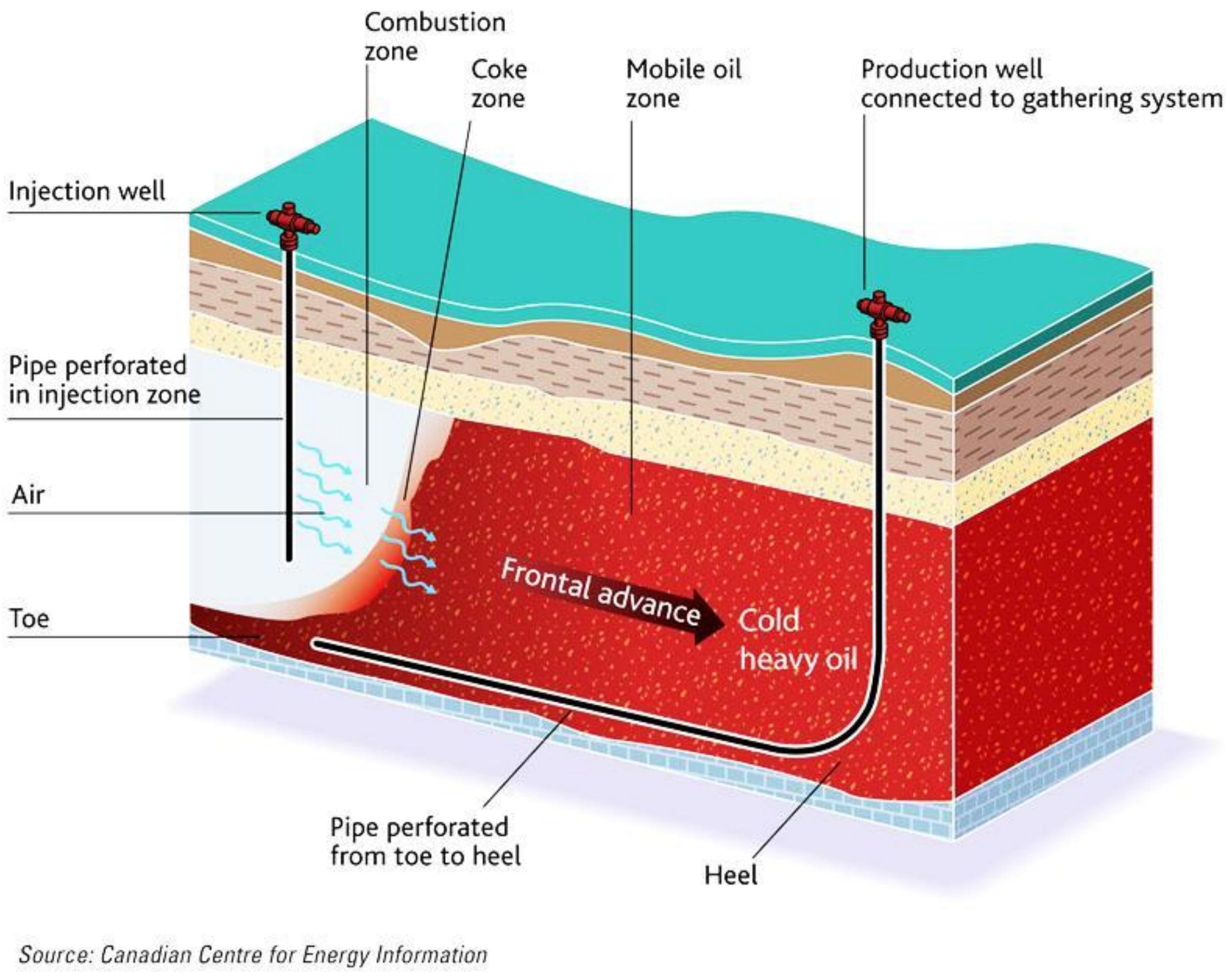


Figure-27 3D view of THAI Process

Let's see what Greaves and Xia (2005) meant by 'Short-distance displacement mechanism' (mentioned earlier), the answer of that was given by Xia, Greaves and Werfilli (2002). They explained it in the form of following figures. They postulated that when the conventional in situ combustion process is Compared to THAI, the path of the mobilized oil to the producer well is much shorter, only about the half of the reservoir thickness, while in the conventional in situ combustion process it is about the half of the distance between the injection and production wells, consider figure-25 (part a). Now if we consider figure-25 (part b), it is show that THAI is a short displacement distance process just like SAGD and VAPEX. The advantage of the short distance displacement is that the mobilized oil does not have to pass through the cold (high viscosity oil) region, but takes the shortest path way to the horizontal production well, shown in figure-25(part c).

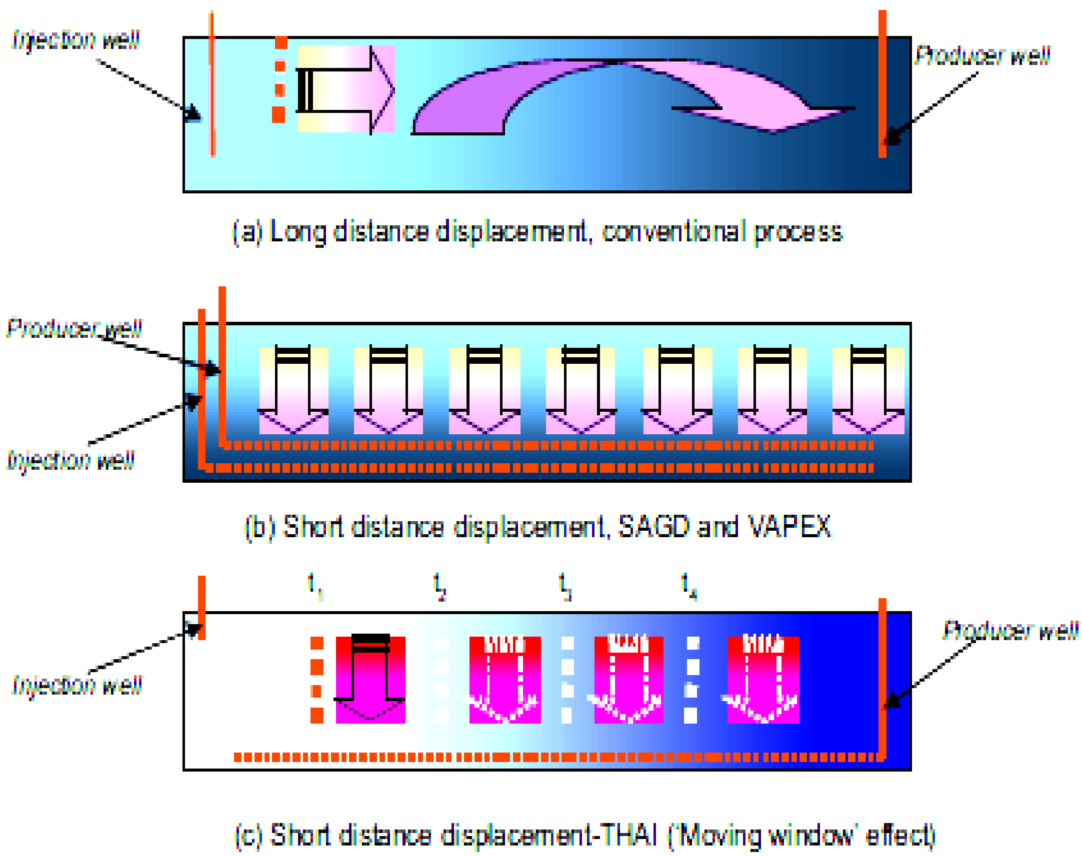


Figure-28 Long distance and short distance displacement processes
[Xia, Greaves and Werfilli (2002)]

THAI has a lower environmental impact so far because it uses negligible amounts of fresh water, produces less greenhouse gas emissions, and involves a smaller surface footprint, allowing for easier reclamation.

5.13. THAI CAPRI PROCESS

Greaves and Xia (2004) gave an idea of in-reservoir refinery that converts heavy components of oil into light components and leaves behind the heaviest components along with metal; they suggest the use of catalyst (either natural or introduced). From that idea we can conclude that this process is an extension of THAI process which involves the refinery type catalyst, which surrounds the horizontal producer well in the bottom of the oil layer in the form of an annular sheath of solid catalyst. When the thermally cracked oil drains into the horizontal producing well, it passes through the layer of catalyst, where the high temperature and pressure in the reservoir provides the desirable condition for hydro conversion reactions and thermal cracking, so that only light, converted oil is produced at the surface.

5.14 ECONOMICS OF POWER GENERATION REQUIRED FOR THE EOR OPERATIONS

Steam and combustion recovery methods require compressors. Steam methods involve the steam generation and in-situ methods require compression of the injected air.

Ramage et.al, (1987), formulated the equations to calculate the fuel cost when oil, gas or steam is used as the fuel in the compressor.

When Oil is used as the fuel,

C_F = (31 B/D) . (365 D/YR) . P_0 N_u
Where,

C_F = Fuel cost in dollars per year

P_0 = The price of oil in dollars per barrel.

N_u= Number of compressing units.

When gas is used as the fuel,

$$C_F = (194.4 \text{ Mcf/D}) \,.\, (365) \,.\, P_0 \,.\, (0.909) \,.\, N_u$$

Where 0.909 is a factor relating the price of gas to the price of oil.

Assumption: The above equations assumes that the energy requirement is 8100 Btu/hp-hr for a 1000 horsepower compressor, which translates into a 31 *B/D* oil fuel consumption, or 194.4 Mcf/D gas fuel consumption.

When steam is used as the fuel,

$$C_F = (i_w /15) \,.\, (365) \,.\, P_0 \; N_u$$

The fuel cost of steam generation depends upon the feed water injection rate. This equation assumes that 1 barrel of fuel oil will produce 15 barrel (water equivalent) of steam.

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The fuel cost of steam generation depends upon the feed water injection rate. This equation assumes that 1 barrel of fuel oil will produce 15 barrel (water equivalent) of steam.

CHAPTER 6 CONCLUSION

As the reserves of conventional oil are declining, further development of heavy oil and oil sands recovery is the need of the hour, there is always an important role of enhance oil recovery after going through the primary and secondary methods. It is not a bad investment to develop the field of heavy oil as the prices of crude oil are going higher. Due to advancement in technology and development of new methods such as drilling, directional drilling and MWD have opened new doors for the development of new technologies in recovery of heavy oil, which include SAGD and VAPEX. These technologies are a welcome addition to the already existing methods such as steam based methods (cyclic steam stimulation and steam drive) and combustion methods, which have already done a lot of good for the heavy oil extraction. All of the technologies specially enhanced oil recovery methods hold great promise for the in situ development of heavy oil, extra heavy oil, and bitumen, which significantly improves sweep efficiency, wellbore reservoir contact, produced oil rate, and production costs.

Table 1 Screening criteria for selection of recovery methods.

S.No	EOR Methods	Oil Properties			Reservoir Characteristics			
		Gravity (API°)	**Viscosity (cP)**	**Oil Saturation (%PV)**	**Formation Type**	**Average Permeability (md)**	**Depth (ft)**	**Net Thickness (ft)**
THERMAL METHODS								
1	Hot water Flood	>12°	50-8000	>12↗	Sand stone	>1000	<3000	>30
2	Steam Drive	>9°-13.5°	4,700 -200,000	>40↗ 66↗	High Porosity sand/ Sand stone	100 ↗	>300↗ <3000	>30
3	Cyclic Steam Injection	>9°-13.5°	4,700 -200,000	>40↗ 66↗	High Porosity sand/ Sand stone	100 ↗	>1000↗ <4,500	>30
4	Steam Assisted Gravity Drainage	>9°-13.5°	4,700 -200,000	>40↗ 66↗	High Porosity sand/ Sand stone	250↗	>1000 ↗ <4,500	60↗
5	In-Situ Combustion	>10°-16°	1,200-5,000	>40↗ 72↗	High Porosity sand/ Sand stone	>50	>11,500 3500↘	>10
GAS INJECTION								
6	Nitrogen and Flu Gases	>35°↗42°↗	<0.4↘ 0.2↘	>40↗ 75↗	Sand stone or carbonate	NC	>6,000	Thin
7	CO2	>22°↗36°↗	<10↘ 1.5↘	>20↗55↗	Sand stone or carbonate	NC	>2,500	Wide Range
(ENHANCED) WATER FLOODING								
8	Alkaline Flooding	>20°↗35°↗	<35 ↘ 13↘	>35↗53↗	Sand Stone preferred	>10↗450↗	>9,000 3,250↘	NC
9	Polymer Flooding	>15°	<150,>10	>50↗90↗	Sand Stone preferred	>10↗900↗	<9,000	NC

NC- Not Critical

Arrow heads are used to show the variations in values which are approximated.

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